Appendix A

Scott J. Rubin
Attorney + Consultant
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Current Position

Public Utility Attorney and Consultant. 1994 to present. I provide legal, consulting, and expert witness services to various organizations interested in the regulation of public utilities.

Previous Positions

Lecturer in Computer Science, Susquehanna University, Selinsgrove, PA. 1993 to 2000.

Senior Assistant Consumer Advocate, Office of Consumer Advocate, Harrisburg, PA. 1990 to 1994. I supervised the administrative and technical staff and shared with one other senior attorney the supervision of a legal staff of 14 attorneys.

Assistant Consumer Advocate, Office of Consumer Advocate, Harrisburg, PA. 1983 to 1990.

Associate, Laws and Staruch, Harrisburg, PA. 1981 to 1983.

Law Clerk, U.S. Environmental Protection Agency, Washington, DC. 1980 to 1981.

Research Assistant, Rockville Consulting Group, Washington, DC. 1979.

Current Professional Activities

Member, American Bar Association, Infrastructure and Regulated Industries Section.

Member, American Water Works Association.

Admitted to practice law before the Supreme Court of Pennsylvania, the New York State Court of Appeals, the United States District Court for the Middle District of Pennsylvania, the United States Court of Appeals for the Third Circuit, and the Supreme Court of the United States.

Previous Professional Activities

Member, American Water Works Association, Rates and Charges Subcommittee, 1998-2001.

Member, Federal Advisory Committee on Disinfectants and Disinfection By-Products in Drinking Water, U.S. Environmental Protection Agency, Washington, DC. 1992 to 1994.

Chair, Water Committee, National Association of State Utility Consumer Advocates, Washington, DC. 1990 to 1994; member of committee from 1988 to 1990.

Member, Board of Directors, Pennsylvania Energy Development Authority, Harrisburg, PA. 1990 to 1994.

Member, Small Water Systems Advisory Committee, Pennsylvania Department of Environmental Resources, Harrisburg, PA. 1990 to 1992.

Member, Ad Hoc Committee on Emissions Control and Acid Rain Compliance, National Association of State Utility Consumer Advocates, 1991.

Member, Nitrogen Oxides Subcommittee of the Acid Rain Advisory Committee, U.S. Environmental Protection Agency, Washington DC. 1991.

Education

J.D. with Honors, George Washington University, Washington, DC. 1981.

B.A. with Distinction in Political Science, Pennsylvania State University, University Park, PA. 1978.

Publications and Presentations (* denotes peer-reviewed publications)

1. "Quality of Service Issues," a speech to the Pennsylvania Public Utility Commission Consumer Conference, State College, PA. 1988.

2. K.L. Pape and S.J. Rubin, "Current Developments in Water Utility Law," in *Pennsylvania Public Utility Law* (Pennsylvania Bar Institute). 1990.

3. Presentation on Water Utility Holding Companies to the Annual Meeting of the National Association of State Utility Consumer Advocates, Orlando, FL. 1990.

4. "How the OCA Approaches Quality of Service Issues," a speech to the Pennsylvania Chapter of the National Association of Water Companies. 1991.

5. Presentation on the Safe Drinking Water Act to the Mid-Year Meeting of the National Association of State Utility Consumer Advocates, Seattle, WA. 1991.

6. "A Consumer Advocate's View of Federal Pre-emption in Electric Utility Cases," a speech to the Pennsylvania Public Utility Commission Electricity Conference. 1991.

7. Workshop on Safe Drinking Water Act Compliance Issues at the Mid-Year Meeting of the National Association of State Utility Consumer Advocates, Washington, DC. 1992.

8. Formal Discussant, Regional Acid Rain Workshop, U.S. Environmental Protection Agency and National Regulatory Research Institute, Charlotte, NC. 1992.

9. S.J. Rubin and S.P. O'Neal, "A Quantitative Assessment of the Viability of Small Water Systems in Pennsylvania," *Proceedings of the Eighth NARUC Biennial Regulatory Information Conference*, National Regulatory Research Institute (Columbus, OH 1992), IV:79-97.

10. "The OCA's Concerns About Drinking Water," a speech to the Pennsylvania Public Utility Commission Water Conference. 1992.

11. Member, Technical Horizons Panel, Annual Meeting of the National Association of Water Companies, Hilton Head, SC. 1992.

12. M.D. Klein and S.J. Rubin, "Water and Sewer -- Update on Clean Streams, Safe Drinking Water, Waste Disposal and Pennvest," *Pennsylvania Public Utility Law Conference* (Pennsylvania Bar Institute). 1992.

13. Presentation on Small Water System Viability to the Technical Assistance Center for Small Water Companies, Pa. Department of Environmental Resources, Harrisburg, PA. 1993

14. "The Results Through a Public Service Commission Lens," speaker and participant in panel discussion at Symposium: "Impact of EPA's Allowance Auction," Washington, DC, sponsored by AER*X. 1993.

15. "The Hottest Legislative Issue of Today -- Reauthorization of the Safe Drinking Water Act," speaker and participant in panel discussion at the Annual Conference of the American Water Works Association, San Antonio, TX. 1993.

16. "Water Service in the Year 2000," a speech to the Conference: "Utilities and Public Policy III: The Challenges of Change," sponsored by the Pennsylvania Public Utility Commission and the Pennsylvania State University, University Park, PA. 1993.

17. "Government Regulation of the Drinking Water Supply: Is it Properly Focused?," speaker and participant in panel discussion at the National Consumers League's Forum on Drinking Water Safety and Quality, Washington, DC. 1993. Reprinted in *Rural Water*, Vol. 15 No. 1 (Spring 1994), pages 13-16.

18. "Telephone Penetration Rates for Renters in Pennsylvania," a study prepared for the Pennsylvania Office of Consumer Advocate. 1993.

19. "Zealous Advocacy, Ethical Limitations and Considerations," participant in panel discussion at "Continuing Legal Education in Ethics for Pennsylvania Lawyers," sponsored by the Office of General Counsel, Commonwealth of Pennsylvania, State College, PA. 1993.

20. "Serving the Customer," participant in panel discussion at the Annual Conference of the National Association of Water Companies, Williamsburg, VA. 1993.

21. "A Simple, Inexpensive, Quantitative Method to Assess the Viability of Small Water Systems," a speech to the Water Supply Symposium, New York Section of the American Water Works Association, Syracuse, NY. 1993.

22. * S.J. Rubin, "Are Water Rates Becoming Unaffordable?," *Journal American Water Works Association*, Vol. 86, No. 2 (February 1994), pages 79-86.

23. "Why Water Rates Will Double (If We're Lucky): Federal Drinking Water Policy and Its Effect on New England," a briefing for the New England Conference of Public Utilities Commissioners, Andover, MA. 1994.

24. "Are Water Rates Becoming Unaffordable?," a speech to the Legislative and Regulatory Conference, Association of Metropolitan Water Agencies, Washington, DC. 1994.

25. "Relationships: Drinking Water, Health, Risk and Affordability," speaker and participant in panel discussion at the Annual Meeting of the Southeastern Association of Regulatory Commissioners, Charleston, SC. 1994.

26. "Small System Viability: Assessment Methods and Implementation Issues," speaker and participant in panel discussion at the Annual Conference of the American Water Works Association, New York, NY. 1994.

27. S.J. Rubin, "How much should we spend to save a life?," *Seattle Journal of Commerce*, August 18, 1994 (Protecting the Environment Supplement), pages B-4 to B-5.

28. S. Rubin, S. Bernow, M. Fulmer, J. Goldstein, and I. Peters, *An Evaluation of Kentucky-American Water Company's Long-Range Planning*, prepared for the Utility and Rate Intervention Division, Kentucky Office of the Attorney General (Tellus Institute 1994).

29. S.J. Rubin, "Small System Monitoring: What Does It Mean?," *Impacts of Monitoring for Phase II/V Drinking Water Regulations on Rural and Small Communities* (National Rural Water Association 1994), pages 6-12.

30. "Surviving the Safe Drinking Water Act," speaker at the Annual Meeting of the National Association of State Utility Consumer Advocates, Reno, NV. 1994.

31. "Safe Drinking Water Act Compliance – Ratemaking Implications," speaker at the National Conference of Regulatory Attorneys, Scottsdale, AZ. 1995. Reprinted in *Water*, Vol. 36, No. 2 (Summer 1995), pages 28-29.

32. S.J. Rubin, "Water: Why Isn't it Free? The Case of Small Utilities in Pennsylvania," *Utilities, Consumers & Public Policy: Issues of Quality, Affordability, and Competition, Proceedings of the Fourth Utilities, Consumers and Public Policy Conference* (Pennsylvania State University 1995), pages 177-183.

33. S.J. Rubin, "Water Rates: An Affordable Housing Issue?," *Home Energy*, Vol. 12 No. 4 (July/August 1995), page 37.

34. Speaker and participant in the Water Policy Forum, sponsored by the National Association of Water Companies, Naples, FL. 1995.

35. Participant in panel discussion on "The Efficient and Effective Maintenance and Delivery of Potable Water at Affordable Rates to the People of New Jersey," at The New Advocacy: Protecting Consumers in the Emerging Era of Utility Competition, a conference sponsored by the New Jersey Division of the Ratepayer Advocate, Newark, NJ. 1995.

36. J.E. Cromwell III, and S.J. Rubin, *Development of Benchmark Measures for Viability Assessment* (Pa. Department of Environmental Protection 1995).

37. S. Rubin, "A Nationwide Practice from a Small Town in Pa.," *Lawyers & the Internet – a Supplement to the Legal Intelligencer and Pa. Law Weekly* (February 12, 1996), page S6.

38. "Changing Customers' Expectations in the Water Industry," speaker at the Mid-America Regulatory Commissioners Conference, Chicago, IL. 1996, reprinted in *Water* Vol. 37 No. 3 (Winter 1997), pages 12-14.

39. "Recent Federal Legislation Affecting Drinking Water Utilities," speaker at Pennsylvania Public Utility Law Conference, Pennsylvania Bar Institute, Hershey, PA. 1996.

40. "Clean Water at Affordable Rates: A Ratepayers Conference," moderator at symposium sponsored by the New Jersey Division of Ratepayer Advocate, Trenton, NJ. 1996.

41. "Water Workshop: How New Laws Will Affect the Economic Regulation of the Water Industry," speaker at the Annual Meeting of the National Association of State Utility Consumer Advocates, San Francisco, CA. 1996.

42. * E.T. Castillo, S.J. Rubin, S.K. Keefe, and R.S. Raucher, "Restructuring Small Systems," *Journal American Water Works Association*, Vol. 89, No. 1 (January 1997), pages 65-74.

43. * J.E. Cromwell III, S.J. Rubin, F.C. Marrocco, and M.E. Leevan, "Business Planning for Small System Capacity Development," *Journal American Water Works Association*, Vol. 89, No. 1 (January 1997), pages 47-57.

44. "Capacity Development – More than Viability Under a New Name," speaker at National Association of Regulatory Utility Commissioners Winter Meetings, Washington, DC. 1997.

45. * E. Castillo, S.K. Keefe, R.S. Raucher, and S.J. Rubin, *Small System Restructuring to Facilitate SDWA Compliance: An Analysis of Potential Feasibility* (AWWA Research Foundation, 1997).

46. H. Himmelberger, *et al.*, *Capacity Development Strategy Report for the Texas Natural Resource Conservation Commission* (Aug. 1997).

47. Briefing on Issues Affecting the Water Utility Industry, Annual Meeting of the National Association of State Utility Consumer Advocates, Boston, MA. 1997.

48. "Capacity Development in the Water Industry," speaker at the Annual Meeting of the National Association of Regulatory Utility Commissioners, Boston, MA. 1997.

49. "The Ticking Bomb: Competitive Electric Metering, Billing, and Collection," speaker at the Annual Meeting of the National Association of State Utility Consumer Advocates, Boston, MA. 1997.

50. Scott J. Rubin, "A Nationwide Look at the Affordability of Water Service," *Proceedings of the 1998 Annual Conference of the American Water Works Association*, Water Research, Vol. C, No. 3, pages 113-129 (American Water Works Association, 1998).

51. Scott J. Rubin, "30 Technology Tips in 30 Minutes," *Pennsylvania Public Utility Law Conference*, Vol. I, pages 101-110 (Pa. Bar Institute, 1998).

52. Scott J. Rubin, "Effects of Electric and Gas Deregulation on the Water Industry," *Pennsylvania Public Utility Law Conference*, Vol. I, pages 139-146 (Pa. Bar Institute, 1998).

53. Scott J. Rubin, *The Challenges and Changing Mission of Utility Consumer Advocates* (American Association of Retired Persons, 1999).

54. "Consumer Advocacy for the Future," speaker at the Age of Awareness Conference, Changes and Choices: Utilities in the New Millennium, Carlisle, PA. 1999.

55. Keynote Address, $1 Energy Fund, Inc., Annual Membership Meeting, Monroeville, PA. 1999.

56. Scott J. Rubin, "Assessing the Effect of the Proposed Radon Rule on the Affordability of Water Service," prepared for the American Water Works Association. 1999.

57. Scott J. Rubin and Janice A. Beecher, The Impacts of Electric Restructuring on the Water and Wastewater Industry, *Proceedings of the Small Drinking Water and Wastewater Systems International Symposium and Technology Expo* (Phoenix, AZ 2000), pp. 66-75.

58. American Water Works Association, *Principles of Water Rates, Fees, and Charges, Manual M1 – Fifth Edition* (AWWA 2000), Member, Editorial Committee.

59. Janice A. Beecher and Scott J. Rubin, presentation on "Special Topics in Rate Design: Affordability" at the Annual Conference and Exhibition of the American Water Works Association, Denver, CO. 2000.

60. Scott J. Rubin, "The Future of Drinking Water Regulation," a speech at the Annual Conference and Exhibition of the American Water Works Association, Denver, CO. 2000.

61. Janice A. Beecher and Scott J. Rubin, "Deregulation Impacts and Opportunities," a presentation at the Annual Conference and Exhibition of the American Water Works Association, Denver, CO. 2000.

62. Scott J. Rubin, "Estimating the Effect of Different Arsenic Maximum Contaminant Levels on the Affordability of Water Service," prepared for the American Water Works Association. 2000.

63. * Janice A. Beecher and Scott J. Rubin, *Deregulation! Impacts on the Water Industry,* American Water Works Association Research Foundation, Denver, CO. 2000.

64. Scott J. Rubin, Methods for Assessing, Evaluating, and Assisting Small Water Systems, NARUC Annual Regulatory Studies Program, East Lansing, MI. 2000.

65. Scott J. Rubin, Consumer Issues in the Water Industry, NARUC Annual Regulatory Studies Program, East Lansing, MI. 2000.

66. "Be Utility Wise in a Restructured Utility Industry," Keynote Address at Be UtilityWise Conference, Pittsburgh, PA. 2000.

67. Scott J. Rubin, Jason D. Sharp, and Todd S. Stewart, "The Wired Administrative Lawyer," *5th Annual Administrative Law Symposium*, Pennsylvania Bar Institute, Harrisburg, PA. 2000.

68. Scott J. Rubin, "Current Developments in the Water Industry," *Pennsylvania Public Utility Law Conference*, Pennsylvania Bar Institute, Harrisburg, PA. 2000.

69. Scott J. Rubin, "Viewpoint: Change Sickening Attitudes," *Engineering News-Record*, Dec. 18, 2000.

70. Janice A. Beecher and Scott J. Rubin, "Ten Practices of Highly Effective Water Utilities," *Opflow*, April 2001, pp. 1, 6-7, 16; reprinted in *Water and Wastes Digest*, December 2004, pp. 22-25.

71. Scott J. Rubin, "Pennsylvania Utilities: How Are Consumers, Workers, and Corporations Faring in the Deregulated Electricity, Gas, and Telephone Industries?" Keystone Research Center. 2001.

72. Scott J. Rubin, "Guest Perspective: A First Look at the Impact of Electric Deregulation on Pennsylvania," *LEAP Letter*, May-June 2001, pp. 2-3.

73. Scott J. Rubin, Consumer Protection in the Water Industry, NARUC Annual Regulatory Studies Program, East Lansing, MI. 2001.

74. Scott J. Rubin, Impacts of Deregulation on the Water Industry, NARUC Annual Regulatory Studies Program, East Lansing, MI. 2001.

75. Scott J. Rubin, "Economic Characteristics of Small Systems," *Critical Issues in Setting Regulatory Standards*, National Rural Water Association, 2001, pp. 7-22.

76. Scott J. Rubin, "Affordability of Water Service," *Critical Issues in Setting Regulatory Standards*, National Rural Water Association, 2001, pp. 23-42.

77. Scott J. Rubin, "Criteria to Assess the Affordability of Water Service," White Paper, National Rural Water Association, 2001.

78. Scott J. Rubin, Providing Affordable Water Service to Low-Income Families, presentation to Portland Water Bureau, Portland, OR. 2001.

79. Scott J. Rubin, Issues Relating to the Affordability and Sustainability of Rates for Water Service, presentation to the Water Utility Council of the American Water Works Association, New Orleans, LA. 2002.

80. Scott J. Rubin, The Utility Industries Compared – Water, NARUC Annual Regulatory Studies Program, East Lansing, MI. 2002.

81. Scott J. Rubin, Legal Perspective on Water Regulation, NARUC Annual Regulatory Studies Program, East Lansing, MI. 2002.

82. Scott J. Rubin, Regulatory Options for Water Utilities, NARUC Annual Regulatory Studies Program, East Lansing, MI. 2002.

83. Scott J. Rubin, Overview of Small Water System Consolidation, presentation to National Drinking Water Advisory Council Small Systems Affordability Working Group, Washington, DC. 2002.

84. Scott J. Rubin, Defining Affordability and Low-Income Household Tradeoffs, presentation to National Drinking Water Advisory Council Small Systems Affordability Working Group, Washington, DC. 2002.

85. Scott J. Rubin, "Thinking Outside the Hearing Room," *Pennsylvania Public Utility Law Conference*, Pennsylvania Bar Institute, Harrisburg, PA. 2002.

86. Scott J. Rubin, "Update of Affordability Database," White Paper, National Rural Water Association. 2003.

87. Scott J. Rubin, *Understanding Telephone Penetration in Pennsylvania*, Council on Utility Choice, Harrisburg, PA. 2003.

88. Scott J. Rubin, *The Cost of Water and Wastewater Service in the United States*, National Rural Water Association, 2003.

89. Scott J. Rubin, What Price Safer Water? Presentation at Annual Conference of National Association of Regulatory Utility Commissioners, Atlanta, GA. 2003.

90. George M. Aman, III, Jeffrey P. Garton, Eric Petersen, and Scott J. Rubin, Challenges and Opportunities for Improving Water Supply Institutional Arrangements, *Water Law Conference*, Pennsylvania Bar Institute, Mechanicsburg, PA. 2004.

91. Scott J. Rubin, Serving Low-Income Water Customers. Presentation at American Water Works Association Annual Conference, Orlando, FL. 2004.

92. Scott J. Rubin, Thinking Outside the Bill: Serving Low-Income Water Customers. Presentation at National League of Cities Annual Congress of Cities, Indianapolis, IN. 2004.

93. Scott J. Rubin, Buying and Selling a Water System – Ratemaking Implications, *Pennsylvania Public Utility Law Conference*, Pennsylvania Bar Institute, Harrisburg, PA. 2005.

94. *Thinking Outside the Bill: A Utility Manager's Guide to Assisting Low-Income Water Customers*, American Water Works Association. 2005; Second Edition published in 2014

95. * Scott J. Rubin, "Census Data Shed Light on US Water and Wastewater Costs," *Journal American Water Works Association*, Vol. 97, No. 4 (April 2005), pages 99-110, reprinted in Maxwell, *The Business of Water. A Concise Overview of Challenges and Opportunities in the Water Market.*, American Water Works Association, Denver, CO. 2008.

96. Scott J. Rubin, Review of U.S. Environmental Protection Agency Notice Concerning Revision of National-Level Affordability Methodology, National Rural Water Association. 2006.

97. * Robert S. Raucher, et al., *Regional Solutions to Water Supply Provision*, American Water Works Association Research Foundation, Denver, CO. 2007; 2nd edition published in 2008.

98. Scott J. Rubin, Robert Raucher, and Megan Harrod, The Relationship Between Household Financial Distress and Health: Implications for Drinking Water Regulation, National Rural Water Association. 2007.

99. * John Cromwell and Scott Rubin, *Estimating Benefits of Regional Solutions for Water and Wastewater Service*, American Water Works Association Research Foundation, Denver, CO. 2008.

100. Scott J. Rubin, "Current State of the Water Industry and Stimulus Bill Overview," in *Pennsylvania Public Utility Law* (Pennsylvania Bar Institute). 2009.

101. Scott J. Rubin, Best Practice in Customer Payment Assistance Programs, webcast presentation sponsored by Water Research Foundation. 2009.

102. * Scott J. Rubin, How Should We Regulate Small Water Utilities?, National Regulatory Research Institute. 2009.

103. * John Cromwell III, et al., *Best Practices in Customer Payment Assistance Programs*, Water Research Foundation, Denver, CO. 2010.

104.* Scott J. Rubin, What Does Water Really Cost? Rate Design Principles for an Era of Supply Shortages, Infrastructure Upgrades, and Enhanced Water Conservation,, National Regulatory Research Institute. 2010.

105. Scott J. Rubin and Christopher P.N. Woodcock, Teleseminar: Water Rate Design, National Regulatory Research Institute. 2010.

106. David Monie and Scott J. Rubin, Cost of Service Studies and Water Rate Design: A Debate on the Utility and Regulatory Perspectives, Meeting of New England Chapter of National Association of Water Companies, Newport, RI. 2010.

107. * Scott J. Rubin, A Call for Water Utility Reliability Standards: Regulating Water Utilities' Infrastructure Programs to Achieve a Balance of Safety, Risk, and Cost, National Regulatory Research Institute. 2010.

108.* Raucher, Robert S.; Rubin, Scott J.; Crawford-Brown, Douglas; and Lawson, Megan M. "Benefit-Cost Analysis for Drinking Water Standards: Efficiency, Equity, and Affordability Considerations in Small Communities," *Journal of Benefit-Cost Analysis*: Vol. 2: Issue 1, Article 4. 2011.

109.Scott J. Rubin, A Call for Reliability Standards, *Journal American Water Works Association*, Vol. 103, No. 1 (Jan. 2011), pp. 22-24.

110.Scott J. Rubin, Current Topics in Water: Rate Design and Reliability. Presentation to the Water Committee of the National Association of Regulatory Utility Commissioners, Washington, DC. 2011.

111.Scott J. Rubin, Water Reliability and Resilience Standards, *Pennsylvania Public Utility Law Conference* (Pennsylvania Bar Institute). 2011.

112.Member of Expert Panel, Leadership Forum: Business Management for the Future, Annual Conference and Exposition of the American Water Works Association, Washington, DC. 2011.

113.Scott J. Rubin, Evaluating Community Affordability in Storm Water Control Plans, *Flowing into the Future: Evolving Water Issues* (Pennsylvania Bar Institute). 2011.

114.Invited Participant, Summit on Declining Water Demand and Revenues, sponsored by The Alliance for Water Efficiency, Racine, WI. 2012.

115.* Scott J. Rubin, Evaluating Violations of Drinking Water Regulations, *Journal American Water Works Association*, Vol. 105, No. 3 (Mar. 2013), pp. 51-52 (Expanded Summary) and E137-E147. Winner of the AWWA Small Systems Division Best Paper Award.

116.* Scott J. Rubin, Structural Changes in the Water Utility Industry During the 2000s, *Journal American Water Works Association*, Vol. 105, No. 3 (Mar. 2013), pp. 53-54 (Expanded Summary) and E148-E156.

117.* Scott J. Rubin, Moving Toward Demand-Based Residential Rates, *The Electricity Journal*, Vol. 28, No. 9 (Nov. 2015), pp. 63-71, http://dx.doi.org/10.1016/j.tej.2015.09.021.

118.Scott J. Rubin, Moving Toward Demand-Based Residential Rates. Presentation at the Annual Meeting of the National Association of State Utility Consumer Advocates, Austin, TX. 2015.

119.* Stacey Isaac Berahzer, et al., *Navigating Legal Pathways to Rate-Funded Customer Assistance Programs: A Guide for Water and Wastewater Utilities*, American Water Works Association, et al. 2017.

120.* Janet Clements, et al., *Customer Assistance Programs for Multi-Family Residential and Other Hard-to-Reach Customers*, Water Research Foundation, Denver, CO. 2017.

121. Scott J. Rubin, Water Costs and Affordability in the US: 1990 to 2015, *Journal American Water Works Association*, Vol. 110, No. 4 (Apr. 2018), pp. 12-16.

Testimony as an Expert Witness

1. *Pa. Public Utility Commission v. Pennsylvania Gas and Water Co. - Water Division*, Pa. Public Utility Commission, Docket R-00922404. 1992. Concerning rate design, on behalf of the Pa. Office of Consumer Advocate.

2. *Pa. Public Utility Commission v. Shenango Valley Water Co.*, Pa. Public Utility Commission, Docket R-00922420. 1992. Concerning cost allocation, on behalf of the Pa. Office of Consumer Advocate

3. *Pa. Public Utility Commission v. Pennsylvania Gas and Water Co. - Water Division*, Pa. Public Utility Commission, Docket R-00922482. 1993. Concerning rate design, on behalf of the Pa. Office of Consumer Advocate

4. *Pa. Public Utility Commission v. Colony Water Co.*, Pa. Public Utility Commission, Docket R-00922375. 1993. Concerning rate design, on behalf of the Pa. Office of Consumer Advocate

5. *Pa. Public Utility Commission v. Dauphin Consolidated Water Supply Co. and General Waterworks of Pennsylvania, Inc*, Pa. Public Utility Commission, Docket R-00932604. 1993. Concerning rate design and cost of service, on behalf of the Pa. Office of Consumer Advocate

6. *West Penn Power Co. v. State Tax Department of West Virginia*, Circuit Court of Kanawha County, West Virginia, Civil Action No. 89-C-3056. 1993. Concerning regulatory policy and the effects of a taxation statute on out-of-state utility ratepayers, on behalf of the Pa. Office of Consumer Advocate

7. *Pa. Public Utility Commission v. Pennsylvania Gas and Water Co. - Water Division*, Pa. Public Utility Commission, Docket R-00932667. 1993. Concerning rate design and affordability of service, on behalf of the Pa. Office of Consumer Advocate

8. *Pa. Public Utility Commission v National Utilities, Inc.*, Pa. Public Utility Commission, Docket R-00932828. 1994. Concerning rate design, on behalf of the Pa. Office of Consumer Advocate

9. *An Investigation of the Sources of Supply and Future Demand of Kentucky-American Water Company*, Ky. Public Service Commission, Case No. 93-434. 1994. Concerning supply and demand planning, on behalf of the Kentucky Office of Attorney General, Utility and Rate Intervention Division.

10. *The Petition on Behalf of Gordon's Corner Water Company for an Increase in Rates*, New Jersey Board of Public Utilities, Docket No. WR94020037. 1994. Concerning revenue requirements and rate design, on behalf of the New Jersey Division of Ratepayer Advocate.

11. *Re Consumers Maine Water Company Request for Approval of Contracts with Consumers Water Company and with Ohio Water Service Company*, Me. Public Utilities Commission, Docket No. 94-352. 1994. Concerning affiliated interest agreements, on behalf of the Maine Public Advocate.

12. *In the Matter of the Application of Potomac Electric Power Company for Approval of its Third Least-Cost Plan*, D.C. Public Service Commission, Formal Case No. 917, Phase II. 1995. Concerning Clean Air Act implementation and environmental externalities, on behalf of the District of Columbia Office of the People's Counsel.

13. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of the Dayton Power and Light Company and Related Matters*, Ohio Public Utilities Commission, Case No. 94-105-EL-EFC. 1995. Concerning Clean Air Act implementation (case settled before testimony was filed), on behalf of the Office of the Ohio Consumers' Counsel.

14. *Kennebec Water District Proposed Increase in Rates*, Maine Public Utilities Commission, Docket No. 95-091. 1995. Concerning the reasonableness of planning decisions and the relationship between a publicly owned water district and a very large industrial customer, on behalf of the Maine Public Advocate.

15. *Winter Harbor Water Company, Proposed Schedule Revisions to Introduce a Readiness-to-Serve Charge*, Maine Public Utilities Commission, Docket No. 95-271. 1995 and 1996. Concerning standards for, and the reasonableness of, imposing a readiness to serve charge and/or exit fee on the customers of a small investor-owned water utility, on behalf of the Maine Public Advocate.

16. *In the Matter of the 1995 Long-Term Electric Forecast Report of the Cincinnati Gas & Electric Company*, Public Utilities Commission of Ohio, Case No. 95-203-EL-FOR, and *In the Matter of the Two-Year Review of the Cincinnati Gas & Electric Company's Environmental Compliance Plan Pursuant to Section 4913.05, Revised Cost*, Case No. 95-747-EL-ECP. 1996. Concerning the reasonableness of the utility's long-range supply and demand-management plans, the reasonableness of its plan for complying with the Clean Air Act Amendments of 1990, and discussing methods to ensure the provision of utility service to low-income customers, on behalf of the Office of the Ohio Consumers' Counsel..

17. *In the Matter of Notice of the Adjustment of the Rates of Kentucky-American Water Company*, Kentucky Public Service Commission, Case No. 95-554. 1996. Concerning rate design, cost of service, and sales forecast issues, on behalf of the Kentucky Office of Attorney General.

18. *In the Matter of the Application of Citizens Utilities Company for a Hearing to Determine the Fair Value of its Properties for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, and to Approve Rate Schedules Designed to Provide such Rate of Return*, Arizona Corporation Commission, Docket Nos. E-1032-95-417, *et al.* 1996. Concerning rate design, cost of service, and the price elasticity of water demand, on behalf of the Arizona Residential Utility Consumer Office.

19. *Cochrane v. Bangor Hydro-Electric Company*, Maine Public Utilities Commission, Docket No. 96-053. 1996. Concerning regulatory requirements for an electric utility to engage in unregulated business enterprises, on behalf of the Maine Public Advocate.

20. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Monongahela Power Company and Related Matters*, Public Utilities Commission of Ohio, Case No. 96-106-EL-EFC. 1996. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

21. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Cleveland Electric Illuminating Company and Toledo Edison Company and Related Matters*, Public Utilities Commission of Ohio, Case Nos. 96-107-EL-EFC and 96-108-EL-EFC. 1996. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

22. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Ohio Power Company and Columbus Southern Power Company and Related Matters*, Public Utilities Commission of Ohio, Case Nos. 96-101-EL-EFC and 96-102-EL-EFC. 1997. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

23. *An Investigation of the Sources of Supply and Future Demand of Kentucky-American Water Company (Phase II)*, Kentucky Public Service Commission, Docket No. 93-434. 1997. Concerning supply and demand planning, on behalf of the Kentucky Office of Attorney General, Public Service Litigation Branch.

24. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Cincinnati Gas and Electric Co. and Related Matters*, Public Utilities Commission of Ohio, Case No. 96-103-EL-EFC. 1997. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

25. *Bangor Hydro-Electric Company Petition for Temporary Rate Increase*, Maine Public Utilities Commission, Docket No. 97-201. 1997. Concerning the reasonableness of granting an electric utility's request for emergency rate relief, and related issues, on behalf of the Maine Public Advocate.

26. *Testimony concerning H B. 1068 Relating to Restructuring of the Natural Gas Utility Industry*, Consumer Affairs Committee, Pennsylvania House of Representatives. 1997. Concerning the provisions of proposed legislation to restructure the natural gas utility industry in Pennsylvania, on behalf of the Pennsylvania AFL-CIO Gas Utility Caucus.

27. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Cleveland Electric Illuminating Company and Toledo Edison Company and Related Matters*, Public Utilities Commission of Ohio, Case Nos. 97-107-EL-EFC and 97-108-EL-EFC. 1997. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

28. *In the Matter of the Petition of Valley Road Sewerage Company for a Revision in Rates and Charges for Water Service*, New Jersey Board of Public Utilities, Docket No. WR92080846J. 1997. Concerning the revenue requirements and rate design for a wastewater treatment utility, on behalf of the New Jersey Division of Ratepayer Advocate.

29. *Bangor Gas Company, L.L.C., Petition for Approval to Furnish Gas Service in the State of Maine*, Maine Public Utilities Commission, Docket No. 97-795. 1998. Concerning the standards and public policy concerns involved in issuing a certificate of public convenience and necessity for a new natural gas utility, and related ratemaking issues, on behalf of the Maine Public Advocate.

30. *In the Matter of the Investigation on Motion of the Commission into the Adequacy of the Public Utility Water Service Provided by Tidewater Utilities, Inc., in Areas in Southern New Castle County, Delaware*,

Delaware Public Service Commission, Docket No. 309-97. 1998. Concerning the standards for the provision of efficient, sufficient, and adequate water service, and the application of those standards to a water utility, on behalf of the Delaware Division of the Public Advocate.

31. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Cincinnati Gas and Electric Co. and Related Matters*, Public Utilities Commission of Ohio, Case No. 97-103-EL-EFC. 1998. Concerning fuel-related transactions with affiliated companies and the appropriate ratemaking treatment and regulatory safeguards involving such transactions, on behalf of the Ohio Consumers' Counsel.

32. *Olde Port Mariner Fleet, Inc. Complaint Regarding Casco Bay Island Transit District's Tour and Charter Service*, Maine Public Utilities Commission, Docket No. 98-161. 1998. Concerning the standards and requirements for allocating costs and separating operations between regulated and unregulated operations of a transportation utility, on behalf of the Maine Public Advocate and Olde Port Mariner Fleet, Inc.

33. *Central Maine Power Company Investigation of Stranded Costs, Transmission and Distribution Utility Revenue Requirements, and Rate Design*, Maine Public Utilities Commission, Docket No. 97-580. 1998. Concerning the treatment of existing rate discounts when designing rates for a transmission and distribution electric utility, on behalf of the Maine Public Advocate.

34. *Pa. Public Utility Commission v. Manufacturers Water Company*, Pennsylvania Public Utility Commission, Docket No. R-00984275. 1998. Concerning rate design on behalf of the Manufacturers Water Industrial Users.

35. *In the Matter of Petition of Pennsgrove Water Supply Company for an Increase in Rates for Water Service*, New Jersey Board of Public Utilities, Docket No. WR98030147. 1998. Concerning the revenue requirements, level of affiliated charges, and rate design for a water utility, on behalf of the New Jersey Division of Ratepayer Advocate.

36. *In the Matter of Petition of Seaview Water Company for an Increase in Rates for Water Service*, New Jersey Board of Public Utilities, Docket No. WR98040193. 1999. Concerning the revenue requirements and rate design for a water utility, on behalf of the New Jersey Division of Ratepayer Advocate.

37. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Ohio Power Company and Columbus Southern Power Company and Related Matters*, Public Utilities Commission of Ohio, Case Nos. 98-101-EL-EFC and 98-102-EL-EFC. 1999. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

38. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Dayton Power and Light Company and Related Matters*, Public Utilities Commission of Ohio, Case No. 98-105-EL-EFC. 1999. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

39. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Monongahela Power Company and Related Matters*, Public Utilities Commission of Ohio, Case No. 99-106-EL-EFC. 1999. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

40. *County of Suffolk, et al. v. Long Island Lighting Company, et al.*, U.S. District Court for the Eastern District of New York, Case No. 87-CV-0646. 2000. Submitted two affidavits concerning the calculation and collection of court-ordered refunds to utility customers, on behalf of counsel for the plaintiffs.

41. *Northern Utilities, Inc., Petition for Waivers from Chapter 820*, Maine Public Utilities Commission, Docket No. 99-254. 2000. Concerning the standards and requirements for defining and separating a natural gas utility's core and non-core business functions, on behalf of the Maine Public Advocate.

42. *Notice of Adjustment of the Rates of Kentucky-American Water Company*, Kentucky Public Service Commission, Case No. 2000-120. 2000. Concerning the appropriate methods for allocating costs and designing rates, on behalf of the Kentucky Office of Attorney General.

43. *In the Matter of the Petition of Gordon's Corner Water Company for an Increase in Rates and Charges for Water Service*, New Jersey Board of Public Utilities, Docket No. WR00050304. 2000. Concerning the revenue requirements and rate design for a water utility, on behalf of the New Jersey Division of Ratepayer Advocate.

44. *Testimony concerning Arsenic in Drinking Water: An Update on the Science, Benefits, and Costs*, Committee on Science, United States House of Representatives. 2001. Concerning the effects on low-income households and small communities from a more stringent regulation of arsenic in drinking water.

45. *In the Matter of the Application of The Cincinnati Gas & Electric Company for an Increase in Gas Rates in its Service Territory*, Public Utilities Commission of Ohio, Case No. 01-1228-GA-AIR, *et al.* 2002. Concerning the need for and structure of a special rider and alternative form of regulation for an accelerated main replacement program, on behalf of the Ohio Consumers' Counsel.

46. *Pennsylvania State Treasurer's Hearing on Enron and Corporate Governance Issues*. 2002. Concerning Enron's role in Pennsylvania's electricity market and related issues, on behalf of the Pennsylvania AFL-CIO.

47. *An Investigation into the Feasibility and Advisability of Kentucky-American Water Company's Proposed Solution to its Water Supply Deficit*, Kentucky Public Service Commission, Case No. 2001-00117. 2002. Concerning water supply planning, regulatory oversight, and related issue, on behalf of the Kentucky Office of Attorney General.

48. *Joint Application of Pennsylvania-American Water Company and Thames Water Aqua Holdings GmbH*, Pennsylvania Public Utility Commission, Docket Nos. A-212285F0096 and A-230073F0004. 2002. Concerning the risks and benefits associated with the proposed acquisition of a water utility, on behalf of the Pennsylvania Office of Consumer Advocate.

49. *Application for Approval of the Transfer of Control of Kentucky-American Water Company to RWE AG and Thames Water Aqua Holdings GmbH*, Kentucky Public Service Commission, Case No. 2002-00018. 2002. Concerning the risks and benefits associated with the proposed acquisition of a water utility, on behalf of the Kentucky Office of Attorney General.

50. *Joint Petition for the Consent and Approval of the Acquisition of the Outstanding Common Stock of American Water Works Company, Inc., the Parent Company and Controlling Shareholder of West Virginia-American Water Company*, West Virginia Public Service Commission, Case No. 01-1691-W-PC. 2002.

Concerning the risks and benefits associated with the proposed acquisition of a water utility, on behalf of the Consumer Advocate Division of the West Virginia Public Service Commission.

51. *Joint Petition of New Jersey-American Water Company, Inc. and Thames Water Aqua Holdings GmbH for Approval of Change in Control of New Jersey-American Water Company, Inc.*, New Jersey Board of Public Utilities, Docket No. WM01120833. 2002. Concerning the risks and benefits associated with the proposed acquisition of a water utility, on behalf of the New Jersey Division of Ratepayer Advocate.

52. *Illinois-American Water Company, Proposed General Increase in Water Rates*, Illinois Commerce Commission, Docket No. 02-0690. 2003. Concerning rate design and cost of service issues, on behalf of the Illinois Office of the Attorney General.

53 *Pennsylvania Public Utility Commission v. Pennsylvania-American Water Company,* Pennsylvania Public Utility Commission, Docket No. R-00038304. 2003. Concerning rate design and cost of service issues, on behalf of the Pennsylvania Office of Consumer Advocate.

54. *West Virginia-American Water Company,* West Virginia Public Service Commission, Case No. 03-0353-W-42T. 2003. Concerning affordability, rate design, and cost of service issues, on behalf of the West Virginia Consumer Advocate Division.

55. *Petition of Seabrook Water Corp. for an Increase in Rates and Charges for Water Service*, New Jersey Board of Public Utilities, Docket No. WR3010054. 2003. Concerning revenue requirements, rate design, prudence, and regulatory policy, on behalf of the New Jersey Division of Ratepayer Advocate.

56. *Chesapeake Ranch Water Co. v. Board of Commissioners of Calvert County*, U.S. District Court for Southern District of Maryland, Civil Action No. 8:03-cv-02527-AW. 2004. Submitted expert report concerning the expected level of rates under various options for serving new commercial development, on behalf of the plaintiff.

57. *Testimony concerning Lead in Drinking Water*, Committee on Government Reform, United States House of Representatives. 2004. Concerning the trade-offs faced by low-income households when drinking water costs increase, including an analysis of H.R. 4268.

58. *West Virginia-American Water Company,* West Virginia Public Service Commission, Case No. 04-0373-W-42T. 2004. Concerning affordability and rate comparisons, on behalf of the West Virginia Consumer Advocate Division.

59. *West Virginia-American Water Company,* West Virginia Public Service Commission, Case No. 04-0358-W-PC. 2004. Concerning costs, benefits, and risks associated with a wholesale water sales contract, on behalf of the West Virginia Consumer Advocate Division.

60. *Kentucky-American Water Company,* Kentucky Public Service Commission, Case No. 2004-00103. 2004. Concerning rate design and tariff issues, on behalf of the Kentucky Office of Attorney General.

61. *New Landing Utility, Inc.,* Illinois Commerce Commission, Docket No. 04-0610. 2005. Concerning the adequacy of service provided by, and standards of performance for, a water and wastewater utility, on behalf of the Illinois Office of Attorney General.

62. *People of the State of Illinois v. New Landing Utility, Inc.*, Circuit Court of the 15th Judicial District, Ogle County, Illinois, No. 00-CH-97. 2005. Concerning the standards of performance for a water and wastewater utility, including whether a receiver should be appointed to manage the utility's operations, on behalf of the Illinois Office of Attorney General.

63. *Hope Gas, Inc. d/b/a Dominion Hope*, West Virginia Public Service Commission, Case No. 05-0304-G-42T. 2005. Concerning the utility's relationships with affiliated companies, including an appropriate level of revenues and expenses associated with services provided to and received from affiliates, on behalf of the West Virginia Consumer Advocate Division.

64. *Monongahela Power Co. and The Potomac Edison Co.*, West Virginia Public Service Commission, Case Nos. 05-0402-E-CN and 05-0750-E-PC. 2005. Concerning review of a plan to finance the construction of pollution control facilities and related issues, on behalf of the West Virginia Consumer Advocate Division.

65. *Joint Application of Duke Energy Corp., et al., for Approval of a Transfer and Acquisition of Control*, Case Kentucky Public Service Commission, No. 2005-00228. 2005. Concerning the risks and benefits associated with the proposed acquisition of an energy utility, on behalf of the Kentucky Office of the Attorney General.

66. *Commonwealth Edison Company proposed general revision of rates, restructuring and price unbundling of bundled service rates, and revision of other terms and conditions of service*, Illinois Commerce Commission, Docket No. 05-0597. 2005. Concerning rate design and cost of service, on behalf of the Illinois Office of Attorney General.

67. *Pennsylvania Public Utility Commission v. Aqua Pennsylvania, Inc.*, Pennsylvania Public Utility Commission, Docket No. R-00051030. 2006. Concerning rate design and cost of service, on behalf of the Pennsylvania Office of Consumer Advocate.

68. *Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, and Illinois Power Company d/b/a AmerenIP, proposed general increases in rates for delivery service*, Illinois Commerce Commission, Docket Nos. 06-0070, et al. 2006. Concerning rate design and cost of service, on behalf of the Illinois Office of Attorney General.

69. *Grens, et al., v. Illinois-American Water Co*, Illinois Commerce Commission, Docket Nos. 5-0681, et al. 2006. Concerning utility billing, metering, meter reading, and customer service practices, on behalf of the Illinois Office of Attorney General and the Village of Homer Glen, Illinois.

70. *Commonwealth Edison Company Petition for Approval of Tariffs Implementing ComEd's Proposed Residential Rate Stabilization Program*, Illinois Commerce Commission, Docket No. 06-0411. 2006. Concerning a utility's proposed purchased power phase-in proposal, in behalf of the Illinois Office of Attorney General.

71. *Illinois-American Water Company, Application for Approval of its Annual Reconciliation of Purchased Water and Purchased Sewage Treatment Surcharges Pursuant to 83 Ill. Adm. Code 655*, Illinois Commerce Commission, Docket No. 06-0196. 2006. Concerning the reconciliation of purchased water and sewer charges, on behalf of the Illinois Office of Attorney General and the Village of Homer Glen, Illinois.

72. *Illinois-American Water Company, et al.*, Illinois Commerce Commission, Docket No. 06-0336. 2006. Concerning the risks and benefits associated with the proposed divestiture of a water utility, on behalf of the Illinois Office of Attorney General.

73. *Joint Petition of Kentucky-American Water Company, et al.*, Kentucky Public Service Commission, Docket No. 2006-00197. 2006. Concerning the risks and benefits associated with the proposed divestiture of a water utility, on behalf of the Kentucky Office of Attorney General.

74. *Aqua Illinois, Inc. Proposed Increase in Water Rates for the Kankakee Division*, Illinois Commerce Commission, Docket No. 06-0285. 2006. Concerning various revenue requirement, rate design, and tariff issues, on behalf of the County of Kankakee.

75. *Housing Authority for the City of Pottsville v. Schuylkill County Municipal Authority*, Court of Common Pleas of Schuylkill County, Pennsylvania, No. S-789-2000. 2006. Concerning the reasonableness and uniformity of rates charged by a municipal water authority, on behalf of the Pottsville Housing Authority.

76. *Application of Pennsylvania-American Water Company for Approval of a Change in Control*, Pennsylvania Public Utility Commission, Docket No. A-212285F0136. 2006. Concerning the risks and benefits associated with the proposed divestiture of a water utility, on behalf of the Pennsylvania Office of Consumer Advocate.

77. *Application of Artesian Water Company, Inc., for an Increase in Water Rates*, Delaware Public Service Commission, Docket No. 06-158. 2006. Concerning rate design and cost of service, on behalf of the Staff of the Delaware Public Service Commission.

78. *Central Illinois Light Company, Central Illinois Public Service Company, and Illinois Power Company: Petition Requesting Approval of Deferral and Securitization of Power Costs*, Illinois Commerce Commission, Docket No. 06-0448. 2006. Concerning a utility's proposed purchased power phase-in proposal, in behalf of the Illinois Office of Attorney General.

79. *Petition of Pennsylvania-American Water Company for Approval to Implement a Tariff Supplement Revising the Distribution System Improvement Charge*, Pennsylvania Public Utility Commission, Docket No. P-00062241. 2007. Concerning the reasonableness of a water utility's proposal to increase the cap on a statutorily authorized distribution system surcharge, on behalf of the Pennsylvania Office of Consumer Advocate.

80. *Adjustment of the Rates of Kentucky-American Water Company*, Kentucky Public Service Commission, Case No. 2007-00143. 2007. Concerning rate design and cost of service, on behalf of the Kentucky Office of Attorney General.

81. *Application of Kentucky-American Water Company for a Certificate of Convenience and Necessity Authorizing the Construction of Kentucky River Station II, Associated Facilities and Transmission Main*, Kentucky Public Service Commission, Case No. 2007-00134. 2007. Concerning the life-cycle costs of a planned water supply source and the imposition of conditions on the construction of that project, on behalf of the Kentucky Office of Attorney General.

82. *Pa. Public Utility Commission v. Pennsylvania-American Water Company*, Pennsylvania Public Utility Commission, Docket No. R-00072229. 2007. Concerning rate design and cost of service, on behalf of the Pennsylvania Office of Consumer Advocate.

83. *Illinois-American Water Company Application for Approval of its Annual Reconciliation of Purchased Water and Purchased Sewage Treatment Surcharges*, Illinois Commerce Commission, Docket No. 07-0195. 2007. Concerning the reconciliation of purchased water and sewer charges, on behalf of the Illinois Office of Attorney General.

84. *In the Matter of the Application of Aqua Ohio, Inc. to Increase Its Rates for Water Service Provided In the Lake Erie Division*, Public Utilities Commission of Ohio, Case No.07-0564-WW-AIR. 2007. Concerning rate design and cost of service, on behalf of the Office of the Ohio Consumers' Counsel.

85. *Pa. Public Utility Commission v. Aqua Pennsylvania Inc.*, Pennsylvania Public Utility Commission, Docket No. R-00072711. 2008. Concerning rate design, on behalf of the Masthope Property Owners Council.

86. *Illinois-American Water Company Proposed increase in water and sewer rates*, Illinois Commerce Commission, Docket No. 07-0507. 2008. Concerning rate design and demand studies, on behalf of the Illinois Office of Attorney General.

87. *Central Illinois Light Company, d/b/a AmerenCILCO; Central Illinois Public Service Company, d/b/a AmerenCIPS; Illinois Power Company, d/b/a AmerenIP: Proposed general increase in rates for electric delivery service*, Illinois Commerce Commission Docket Nos. 07-0585, 07-0586, 07-0587. 2008. Concerning rate design and cost of service studies, on behalf of the Illinois Office of Attorney General.

88. *Commonwealth Edison Company: Proposed general increase in electric rates*, Illinois Commerce Commission Docket No. 07-0566. 2008. Concerning rate design and cost of service studies, on behalf of the Illinois Office of Attorney General.

89. *In the Matter of Application of Ohio American Water Co. to Increase Its Rates*, Public Utilities Commission of Ohio, Case No. 07-1112-WS-AIR. 2008. Concerning rate design and cost of service, on behalf of the Office of the Ohio Consumers' Counsel.

90. *In the Matter of the Application of The East Ohio Gas Company d/b/a Dominion East Ohio for Authority to Increase Rates for its Gas Service*, Public Utilities Commission of Ohio, Case Nos. 07-829-GA-AIR, et al. 2008. Concerning the need for, and structure of, an accelerated infrastructure replacement program and rate surcharge, on behalf of the Office of the Ohio Consumers' Counsel.

91. *Pa. Public Utility Commission v. Pennsylvania American Water Company*, Pennsylvania Public Utility Commission, Docket No. R-2008-2032689. 2008. Concerning rate design, cost of service study, and other tariff issues, on behalf of the Pennsylvania Office of Consumer Advocate.

92. *Pa. Public Utility Commission v. York Water Company*, Pennsylvania Public Utility Commission, Docket No. R-2008-2023067. 2008. Concerning rate design, cost of service study, and other tariff issues, on behalf of the Pennsylvania Office of Consumer Advocate.

93. *Northern Illinois Gas Company d/b/a Nicor Gas Company*, Illinois Commerce Commission, Docket No. 08-0363. 2008. Concerning rate design, cost of service, and automatic rate adjustments, on behalf of the Illinois Office of Attorney General.

94. *West Virginia American Water Company,* West Virginia Public Service Commission, Case No. 08-0900-W-42T. 2008. Concerning affiliated interest charges and relationships, on behalf of the Consumer Advocate Division of the Public Service Commission of West Virginia.

95. *Illinois-American Water Company Application for Approval of its Annual Reconciliation of Purchased Water and Purchased Sewage Treatment Surcharges*, Illinois Commerce Commission, Docket No. 08-0218. 2008. Concerning the reconciliation of purchased water and sewer charges, on behalf of the Illinois Office of Attorney General.

96. *In the Matter of Application of Duke Energy Ohio, Inc for an Increase in Electric Rates*, Public Utilities Commission of Ohio, Case No. 08-0709-EL-AIR. 2009. Concerning rate design and cost of service, on behalf of the Office of the Ohio Consumers' Counsel.

97. *The Peoples Gas Light and Coke Company and North Shore Gas Company Proposed General Increase in Rates for Gas Service*, Illinois Commerce Commission, Docket Nos. 09-0166 and 09-0167. 2009. Concerning rate design and automatic rate adjustments on behalf of the Illinois Office of Attorney General, Citizens Utility Board, and City of Chicago.

98. *Illinois-American Water Company Proposed Increase in Water and Sewer Rates*, Illinois Commerce Commission, Docket No. 09-0319. 2009. Concerning rate design and cost of service on behalf of the Illinois Office of Attorney General and Citizens Utility Board.

99. *Pa. Public Utility Commission v. Aqua Pennsylvania Inc.*, Pennsylvania Public Utility Commission, Docket No. R-2009-2132019. 2010. Concerning rate design, cost of service, and automatic adjustment tariffs, on behalf of the Pennsylvania Office of Consumer Advocate.

100. *Apple Canyon Utility Company and Lake Wildwood Utilities Corporation Proposed General Increases in Water Rates*, Illinois Commerce Commission, Docket Nos. 09-0548 and 09-0549. 2010. Concerning parent-company charges, quality of service, and other matters, on behalf of Apple Canyon Lake Property Owners' Association and Lake Wildwood Association, Inc.

101. *Application of Aquarion Water Company of Connecticut to Amend its Rate Schedules*, Connecticut Department of Public Utility Control, Docket No. 10-02-13. 2010. Concerning rate design, proof of revenues, and other tariff issues, on behalf of the Connecticut Office of Consumer Counsel.

102. *Illinois-American Water Company Annual Reconciliation Of Purchased Water and Sewage Treatment Surcharges*, Illinois Commerce Commission, Docket No. 09-0151. 2010. Concerning the reconciliation of purchased water and sewer charges, on behalf of the Illinois Office of Attorney General.

103. *Pa. Public Utility Commission v. Pennsylvania-American Water Co.*, Pennsylvania Public Utility Commission, Docket Nos. R-2010-2166212, et al. 2010. Concerning rate design and cost of service study for four wastewater utility districts, on behalf of the Pennsylvania Office of Consumer Advocate.

104. *Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, Illinois Power Company d/b/a AmerenIP Petition for accounting order*, Illinois Commerce Commission, Docket No. 10-0517. 2010. Concerning ratemaking procedures for a multi-district electric and natural gas utility, on behalf of the Illinois Office of Attorney General.

105. *Commonwealth Edison Company Petition for General Increase in Delivery Service Rates*, Illinois Commerce Commission Docket No. 10-0467. 2010. Concerning rate design and cost of service study, on behalf of the Illinois Office of Attorney General.

106. *Pa. Public Utility Commission v. City of Lancaster Bureau of Water*, Pennsylvania Public Utility Commission, Docket No. R-2010-2179103. 2010. Concerning rate design, cost of service, and cost allocation, on behalf of the Pennsylvania Office of Consumer Advocate.

107. *Application of Yankee Gas Services Company for Amended Rate Schedules*, Connecticut Department of Public Utility Control, Docket No. 10-12-02. 2011. Concerning rate design and cost of service for a natural gas utility, on behalf of the Connecticut Office of Consumers' Counsel.

108. *California-American Water Company*, California Public Utilities Commission, Application 10-07-007. 2011. Concerning rate design and cost of service for multiple water-utility service areas, on behalf of The Utility Reform Network.

109. *Little Washington Wastewater Company, Inc., Masthope Wastewater Division*, Pennsylvania Public Utility Commission Docket No. R-2010-2207833. 2011. Concerning rate design and various revenue requirements issues, on behalf of the Masthope Property Owners Council.

110. *In the matter of Pittsfield Aqueduct Company, Inc.*, New Hampshire Public Utilities Commission Case No. DW 10-090. 2011. Concerning rate design and cost of service on behalf of the New Hampshire Office of the Consumer Advocate.

111. *In the matters of Pennichuck Water Works, Inc. Permanent Rate Case and Petition for Approval of Special Contract with Anheuser-Busch, Inc.*, New Hampshire Public Utilities Commission Case Nos. DW 10-091 and DW 11-014. 2011. Concerning rate design, cost of service, and contract interpretation on behalf of the New Hampshire Office of the Consumer Advocate.

112. *Artesian Water Co., Inc. v. Chester Water Authority*, U.S. District Court for the Eastern District of Pennsylvania Case No. 10-CV-07453-JP. 2011. Concerning cost of service, ratemaking methods, and contract interpretation on behalf of Chester Water Authority.

113. *North Shore Gas Company and The Peoples Gas Light and Coke Company Proposed General Increases in Rates for Gas Service*, Illinois Commerce Commission, Docket Nos. 11-0280 and 11-0281. 2011. Concerning rate design and cost of service on behalf of the Illinois Office of Attorney General, the Citizens Utility Board, and the City of Chicago.

114. *Ameren Illinois Company: Proposed general increase in electric delivery service rates and gas delivery service rates*, Illinois Commerce Commission, Docket Nos. 11-0279 and 11-0282. 2011. Concerning rate design and cost of service for natural gas and electric distribution service, on behalf of the Illinois Office of Attorney General and the Citizens Utility Board.

115. *Pa. Public Utility Commission v. Pennsylvania-American Water Co.*, Pennsylvania Public Utility Commission, Docket No. R-2011-2232243. 2011. Concerning rate design, cost of service, sales forecast, and automatic rate adjustments on behalf of the Pennsylvania Office of Consumer Advocate.

116. *Aqua Illinois, Inc. Proposed General Increase in Water and Sewer Rates*, Illinois Commerce Commission, Docket No. 11-0436. 2011. Concerning rate design and cost of service on behalf of the

Illinois Office of Attorney General.

117. *City of Nashua Acquisition of Pennichuck Corporation*, New Hampshire Public Utilities Commission, Docket No. DW 11-026. 2011. Concerning the proposed acquisition of an investor-owned utility holding company by a municipality, including appropriate ratemaking methodologies, on behalf of the New Hampshire Office of Consumer Advocate.

118. *An Application by Heritage Gas Limited for the Approval of a Schedule of Rates, Tolls and Charges*, Nova Scotia Utility and Review Board, Case NSUARB-NG-HG-R-11. 2011. Concerning rate design and cost of service, on behalf of the Nova Scotia Consumer Advocate.

119. *An Application of Halifax Regional Water Commission for Approval of a Cost of Service and Rate Design Methodology*, Nova Scotia Utility and Review Board , Case NSUARB-W-HRWC-R-11. 2011. Concerning rate design and cost of service, on behalf of the Nova Scotia Consumer Advocate.

120. *National Grid USA and Liberty Energy Utilities Corp.*, New Hampshire Public Utilities Commission, Docket No. DG 11-040. 2011. Concerning the costs and benefits of a proposed merger and related conditions, on behalf of the New Hampshire Office of Consumer Advocate.

121. *Great Northern Utilities, Inc., et al.*, Illinois Commerce Commission, Docket Nos. 11-0059, et al. 2012. Concerning options for mitigating rate impacts and consolidating small water and wastewater utilities for ratemaking purposes, on behalf of the Illinois Office of Attorney General.

122. *Pa. Public Utility Commission v. Aqua Pennsylvania, Inc.*, Pennsylvania Public Utility Commission, Docket No. R-2011-2267958. 2012. Concerning rate design, cost of service, and automatic rate adjustment mechanisms, on behalf of the Pennsylvania Office of Consumer Advocate.

123. *Golden State Water Company*, California Public Utilities Commission, Application 11-07-017. 2012. Concerning rate design and quality of service, on behalf of The Utility Reform Network.

124. *Golden Heart Utilities, Inc. and College Utilities Corporation*, Regulatory Commission of Alaska, Case Nos. U-11-77 and U-11-78. 2012. Concerning rate design and cost of service, on behalf of the Alaska Office of the Attorney General.

125. *Illinois-American Water Company*, Illinois Commerce Commission, Docket No. 11-0767. 2012. Concerning rate design, cost of service, and automatic rate adjustment mechanisms, on behalf of the Illinois Office of Attorney General.

126. *Application of Tidewater Utilities, Inc , for a General Rate Increase in Water Base Rates and Tariff Revisions*, Delaware Public Service Commission, Docket No. 11-397. 2012. Concerning rate design and cost of service study, on behalf of the Staff of the Delaware Public Service Commission.

127. *In the Matter of the Philadelphia Water Department's Proposed Increase in Rates for Water and Wastewater Utility Services*, Philadelphia Water Commissioner, FY 2013-2016. 2012. Concerning rate design and related issues for storm water service, on behalf of Citizens for Pennsylvania's Future.

128. *Corix Utilities (Illinois) LLC, Hydro Star LLC, and Utilities Inc. Joint Application for Approval of a Proposed Reorganization*, Illinois Commerce Commission, Docket No. 12-0279. 2012. Concerning merger-related synergy savings and appropriate ratemaking treatment of the same, on behalf of the

Illinois Office of Attorney General.

129. *North Shore Gas Company and The Peoples Gas Light and Coke Company*, Illinois Commerce Commission, Docket Nos. 12-0511 and 12-0512. 2012. Concerning rate design, cost of service study, and automatic rate adjustment tariff on behalf of the Illinois Office of Attorney General.

130. *Pa. Public Utility Commission v. City of Lancaster Sewer Fund*, Pennsylvania Public Utility Commission, Docket No. R-2012-2310366. 2012. Concerning rate design, cost of service, and cost allocation, on behalf of the Pennsylvania Office of Consumer Advocate.

131. *Aquarion Water Company of New Hampshire*, New Hampshire Public Utilities Commission, Docket No. DW 12-085. 2013. Concerning tariff issues, including an automatic adjustment clause for infrastructure improvement, on behalf of the New Hampshire Office of Consumer Advocate.

132. *In the Matter of the Application of Duke Energy Ohio, Inc., for an Increase in Electric Distribution Rates*, Public Utilities Commission of Ohio, Case No. 12-1682-EL-AIR, et al. 2013. Concerning rate design and tariff issues, on behalf of the Office of the Ohio Consumers' Counsel.

133. *In the Matter of the Application of Duke Energy Ohio, Inc., for an Increase in Natural Gas Distribution Rates*, Public Utilities Commission of Ohio, Case No. 12-1685-GA-AIR, et al. 2013. Concerning cost-of-service study, rate design, and tariff issues, on behalf of the Office of the Ohio Consumers' Counsel.

134. *In the Matter of the Application of The Dayton Power and Light Company to Establish a Standard Service Offer in the Form of an Electric Security Plan*, Public Utilities Commission of Ohio, Case No. 12-426-EL-SSO, et al. 2013. Concerning rate design, on behalf of the Office of the Ohio Consumers' Counsel.

135. *Application of the Halifax Regional Water Commission, for Approval of Amendments to its Schedule of Rates and Charges and Schedule of Rules and Regulations for the delivery of water, public and private fire protection, wastewater and stormwater services*, Nova Scotia Utility and Review Board, Matter No. M05463, 2013. Concerning rate design, cost-of-service study, and miscellaneous tariff provisions, on behalf of the Consumer Advocate of Nova Scotia.

136. *California Water Service Co. General Rate Case Application* , California Public Utilities Commission, Docket No. A.12-07-007. 2013. Concerning rate design, phase-in plans, low-income programs, and other tariff issues, on behalf of The Utility Reform Network.

137. *Application of The United Illuminating Company to Amend its Rate Schedules*, Connecticut Public Utility Regulatory Authority, Docket No. 13-01-19. 2013. Concerning sales forecast, rate design, and other tariff issues, on behalf of the Connecticut Office of Consumer Counsel.

138. *Application of Aquarion Water Company of Connecticut to Amend its Rate Schedules*, Connecticut Public Utility Regulatory Authority, Docket No. 13-02-20. 2013. Concerning sales forecast and rate design on behalf of the Connecticut Office of Consumer Counsel.

139. *Ameren Illinois Company, Proposed General Increase in Natural Gas Delivery Service Rates*, Illinois Commerce Commission, Docket No. 13-0192. 2013. Concerning rate design and revenue allocation, on behalf of the Illinois Office of Attorney General and Citizens Utility Board.

140. *Commonwealth Edison Company, Tariff filing to present the Illinois Commerce Commission with an opportunity to consider revenue neutral tariff changes related to rate design*, Docket No. 13-0387. 2013. Concerning rate design and cost of service study issues, on behalf of the Illinois Office of Attorney General.

141. *In the Matter of the Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service*, District of Columbia Public Service Commission, Formal Case No. 1103. 2013. Concerning rate design, revenue allocation, and cost-of-service study issues, on behalf of the District of Columbia Office of Peoples' Counsel.

142. *Pa. Public Utility Commission v. Pennsylvania-American Water Co.*, Pennsylvania Public Utility Commission, Docket No. R-2013-2355276. 2013. Concerning rate design, revenue allocation, and regulatory policy, on behalf of the Pennsylvania Office of Consumer Advocate.

143. *In the Matter of the Revenue Requirement and Transmission Tariff Designated as TA364-8 filed by Chugach Electric Association, Inc.*, Regulatory Commission of Alaska, U-13-007. 2013. Concerning rate design and cost-of-service study issues, on behalf of the Alaska Office of the Attorney General.

144. *Ameren Illinois Company: Tariff filing to present the Illinois Commerce Commission with an opportunity to consider revenue neutral tariff changes related to rate design*, Docket No. 13-0476. 2013. Concerning rate design and cost of service study issues, on behalf of the Illinois Office of Attorney General.

145. *Pa. Public Utility Commission v. City of Bethlehem Bureau of Water*, Pennsylvania Public Utility Commission, Docket No. R-2013-2390244. 2014. Concerning rate design, cost of service study, and revenue allocation on behalf of the Pennsylvania Office of Consumer Advocate.

146. *In the Matter of the Tariff Revision Designated as TA332-121 filed by the Municipality of Anchorage d/b/a Municipal Light and Power Department*, Regulatory Commission of Alaska, U-13-184. 2014. Concerning rate design and cost-of-service study issues, on behalf of the Alaska Office of the Attorney General.

147. *Pa. Public Utility Commission v. Pike County Light and Power Co. - Gas*, Pennsylvania Public Utility Commission, Docket No. R-2013-2397353. 2014. Concerning rate design and revenue allocation on behalf of the Pennsylvania Office of Consumer Advocate.

148. *Pa. Public Utility Commission v. Pike County Light and Power Co. - Electric*, Pennsylvania Public Utility Commission, Docket No. R-2013-2397237. 2014. Concerning rate design, cost of service study, and revenue allocation on behalf of the Pennsylvania Office of Consumer Advocate.

149. *The Peoples Gas Light and Coke Company North Shore Gas Company Proposed General Increase In Rates for Gas Service*, Illinois Commerce Commission, Docket Nos. 14-0224 and 14-0225. 2014. Concerning rate design on behalf of the Illinois Office of the Attorney General and the Environmental Law and Policy Center.

150. *Apple Valley Ranchos Water Company*, California Public Utilities Commission, Docket No. A.14-01-002. 2014. Concerning rate design and automatic rate adjustment mechanisms on behalf of the Town of Apple Valley.

151.*Application by Heritage Gas Limited for Approval to Amend its Franchise Area*, Nova Scotia Utility and Review Board, Matter No. M06271. 2014. Concerning criteria, terms, and conditions for expanding a utility's service area and using transported compressed natural gas to serve small retail customers, on behalf of the Nova Scotia Consumer Advocate.

152.*Notice of Intent of Entergy Mississippi, Inc. to Modernize Rates to Support Economic Development, Power Procurement, and Continued Investment*, Mississippi Public Service Commission Docket No. 2014-UN-132. 2014. Concerning rate design and tariff issues, on behalf of the Mississippi Public Utilities Staff.

153.*Pa. Public Utility Commission v. City of Lancaster Bureau of Water*, Pennsylvania Public Utility Commission, Docket No. R-2014-2418872. 2014. Concerning rate design, cost of service study, and revenue allocation on behalf of the Pennsylvania Office of Consumer Advocate.

154.*Pa. Public Utility Commission v. Borough of Hanover Municipal Water Works*, Pennsylvania Public Utility Commission, Docket No. R-2014-2428304. 2014. Concerning rate design, cost of service study, and revenue allocation on behalf of the Pennsylvania Office of Consumer Advocate.

155.*Investigation of Commonwealth Edison Company's Cost of Service for Low-Use Customers In Each Residential Class*, Illinois Commerce Commission, Docket No. 14-0384. 2014. Concerning rate design on behalf of the Illinois Office of Attorney General.

156.*Application of the Halifax Regional Water Commission, for Approval of its Schedule of Rates and Charges and Schedule of Rules and Regulations for the Provision of Water, Public and Private Fire Protection, Wastewater and Stormwater Services*, Nova Scotia Utility and Review Board, Matter No. M06540. 2015. Concerning rate design, cost of service study, and tariff issues on behalf of the Nova Scotia Consumer Advocate.

157.*Testimony concerning organization and regulation of Philadelphia Gas Works*, Philadelphia City Council's Special Committee on Energy Opportunities. 2015.

158.*Testimony concerning proposed telecommunications legislation*, Maine Joint Standing Committee on Energy, Utilities, and Technology. 2015.

159.*Pa. Public Utility Commission v. United Water Pennsylvania, Inc.*, Pennsylvania Public Utility Commission, Docket No. R-2015-2462723. 2015. Concerning rate design, cost of service study, and revenue allocation on behalf of the Pennsylvania Office of Consumer Advocate.

160.*Ameren Illinois Company Proposed General Increase in Gas Delivery Service Rates*, Illinois Commerce Commission, Docket No. 15-0142. 2015. Concerning rate design on behalf of the Illinois Office of Attorney General.

161.*Maine Natural Gas Company Request for Multi-Year Rate Plan*, Maine Public Utilities Commission, Docket No. 2015-00005. 2015. Concerning rate design and automatic rate adjustment tariffs on behalf of the Maine Office of the Public Advocate.

162.*Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Provide for a Standard Service Offer*, Public Utilities Commission of Ohio, Case No. 14-1297-EL-SSO. 2015. Concerning rate design and proposed rate discounts on behalf of the Office of the Ohio Consumers' Counsel.

163. *An Application of the Halifax Regional Water Commission, for approval of revisions to its Cost of Service Manual and Rate Design for Stormwater Service*, Nova Scotia Utility and Review Board, Matter No. M07147. 2016. Concerning stormwater rate design and cost of service, on behalf of the Nova Scotia Consumer Advocate.

164. *In The Matter Of An Application By Heritage Gas Limited For Enhancement To Its Existing Residential Retro-Fit Assistance Fund*, Nova Scotia Utility and Review Board, Matter No. M07146. 2016. Concerning costs and benefits associated with utility system expansion, on behalf of the Nova Scotia Consumer Advocate.

165. *In the Matter of the Application of UNS Electric, Inc. for the Establishment of Just and Reasonable Rates and Charges*, Arizona Corporation Commission, Docket No. E-04204A-15-0142. 2016. Concerning rate design and residential demand charges on behalf of Arizona Utility Ratepayer Alliance.

166. *In the Matter of Application of Water Service Corporation of Kentucky for a General Adjustment in Existing Rates*, Kentucky Public Service Commission, Case No. 2015-00382. 2016. Concerning rate design and service area consolidation on behalf of the Kentucky Office of the Attorney General.

167. *Massachusetts Electric Company And Nantucket Electric Company*, Massachusetts Department of Public Utilities, Docket No. DPU 15-155. 2016. Concerning rate design and cost-of-service studies on behalf of the Massachusetts Office of Attorney General.

168. *In the Matter of Abenaki Water Company*, New Hampshire Public Utilities Commission, Docket No. DW 15-199. 2016. Concerning rate design on behalf of the New Hampshire Office of the Consumer Advocate.

169. *In the Matter of an Application by Heritage Gas Limited for Approval of its Customer Retention Program*, Nova Scotia Utility and Review Board Matter No. M07346. 2016. Concerning a regulatory response to competition and potential business failure on behalf of the Nova Scotia Consumer Advocate.

170. *Joint Application of Pennsylvania-American Water Company and the Sewer Authority of the City of Scranton*, Pennsylvania Public Utility Commission Docket No. A-2016-2537209. 2016. Concerning the lawfulness, costs and benefits, and ratemaking treatment of a proposed acquisition of a combined wastewater and storm water utility on behalf of the Pennsylvania Office of Consumer Advocate.

171. *Application of The United Illuminating Company to Amend its Rate Schedules*, Connecticut Public Utility Regulatory Authority Docket No. 16-06-04. 2016. Concerning rate design, cost-of-service study, and other tariff issues on behalf of the Connecticut Office of Consumer Counsel.

172. *Ameren Illinois Company Tariff filing to present the Illinois Commerce Commission with an opportunity to consider revenue neutral tariff changes related to rate design*, Illinois Commerce Commission Docket No. 16-0387. 2016. Concerning rate design and cost-of-service study on behalf of the Illinois Office of the Attorney General.

173. *Unitil Energy Systems, Inc.*, New Hampshire Public Utilities Commission Docket No. 16-384. 2016. Concerning rate design and cost-of-service study on behalf of the New Hampshire Office of Consumer

Advocate.

174. *Liberty Utilities (Granite State Electric) Corp.*, New Hampshire Public Utilities Commission Docket No. 16-383. 2016. Concerning rate design and cost-of-service study on behalf of the New Hampshire Office of Consumer Advocate.

175. *Arizona Public Service Co.*, Arizona Corporation Commission Docket No. E-01345A-16-0123. 2017. Concerning rate design and cost-of-service study on behalf of the Arizona Utility Ratepayer Alliance.

176. *Commonwealth Edison Company, Tariff filing to present the Illinois Commerce Commission with an opportunity to consider revenue neutral tariff changes related to rate design*, Illinois Commerce Commission Docket No. 17-0049. 2017. Concerning rate design and cost of service study issues, on behalf of the Illinois Office of Attorney General.

177. *NSTAR Electric Company and Western Massachusetts Electric Company*, Massachusetts Department of Public Utilities Docket No. D.P.U. 17-05. 2017. Concerning rate design and cost of service study issues, on behalf of the Massachusetts Office of Attorney General.

178. *In the Matter of the Tariff Revision Designated as TA857-2 Filed by Alaska Power Company*, Regulatory Commission of Alaska No. U-16-078. 2017. Concerning rate design and cost of service study issues on behalf of the Alaska Office of the Attorney General.

179. *In the Matter of the Application of Minnesota Power For Authority to Increase Rates for Electric Utility Service in Minnesota*, Minnesota Public Utilities Commission Docket No. E015/GR-16-664. 2017. Concerning rate design and cost of service study issues on behalf of AARP.

180. *Pennsylvania Public Utility Commission v. Pennsylvania-American Water Company,* Pennsylvania Public Utility Commission, Docket No. R-2017-2595853. 2017. Concerning rate design, cost of service, and policy issues, on behalf of the Pennsylvania Office of Consumer Advocate.

181. *Aqua Illinois, Inc. Proposed Rate Increases for Water and Sewer Services*, Illinois Commerce Commission, Docket No. 17-0259. 2017. Concerning rate design and single-tariff pricing, on behalf of the Illinois Office of Attorney General.

182. *Petition of Pennsylvania-American Water Company for Approval of Tariff Changes and Accounting and Rate Treatment Related to Replacement of Lead Customer-Owned Service Pipes*, Pennsylvania Public Utility Commission, Docket No. P-2017-2606100. 2017. Concerning public policy and ratemaking issues associated with the replacement of customer-owned lead service lines, on behalf of the Pennsylvania Office of Consumer Advocate.

183. *In the Matter of Application and Notice of Change in Natural Gas Rates of Montana-Dakota Utilities Co.*, North Dakota Public Service Commission, Case No. PU-17-295. 2017. Concerning rate design and cost of service study issues, on behalf of AARP.

184. *Aqua Illinois, Inc. Petition for the Issuance of a Certificate of Public Convenience and Necessity to Operate a Water and Wastewater System in the Village of Peotone*, Illinois Commerce Commission, Docket No. 17-0314. 2018. Concerning rate consolidation and rate design, on behalf of the Illinois Office of Attorney General.

185. *Application Of The Connecticut Light and Power Company d/b/a Eversource Energy to Amend Its Rate Schedules, Connecticut Public Utilities Regulatory Authority*, Docket No. 17-10-46. 2018. Concerning rate design issues, on behalf of the Connecticut Office of Consumer Counsel.

186. *Application by Heritage Gas for Approval of a Long-Term Natural Gas Transportation Contract and Cost Recovery Mechanism*, Nova Scotia Utility and Review Board, Matter M08473. 2018. Concerning evaluation of costs, benefits, and risks of a long-term natural gas pipeline contract, on behalf of the Consumer Advocate of Nova Scotia.

187. *Boston Gas Company and Colonial Gas Company*, Massachusetts Department of Public Utilities, D.P.U. 17-170. 2018. Concerning class revenue allocation and rate design, on behalf of the Massachusetts Office of Attorney General.

188. *In the Matter of the Application of Maryland-American Water Company for Authority to Adjust its Existing Schedule of Tariffs and Rates*, Maryland Public Service Commission, Case No. 9487. 2018. Concerning cost-of-service study, on behalf of the Staff of the Maryland Public Service Commission.

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May 6, 2014

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Subject: V.C. Summer Units 2 and 3 Guaranteed Substantial Completion Dates

Reference: (1) Engineering, Procurement, and Construction Agreement for AP 1000 Nuclear Power Plants, Dated May 23, 2008 – V.C. Summer Units 2 and 3

(2) VSP_VSG_002024, dated August 6, 2012

Gentlemen:

On May 23, 2008, we executed the EPC Agreement with the Consortium for Units 2 and 3 at our V.C Summer nuclear facility. That was an historic day for our companies. We would like to believe that it was equally significant to you. Together, we helped kick off what we continue to hope will be a new wave of nuclear construction in this country.

The V.C. Summer facility offers the best template for future projects. Although you signed EPC agreements with two other utilities at about the same time, both of those projects are currently embroiled in major litigation. We chose a different path. We resolved to work with you amicably, believing that building the project cooperatively, on time and on budget, would be in the best interests of all involved.

The events since May 23, 2008 have tested our resolve. In this letter, we will review certain of those events for the benefit of your current management. We believe that such a review is called for because of the many turnovers in your management since May 23, 2008. With one possible exception, no one from your two companies who attended the signing ceremony is still involved in the project. Since then, Westinghouse has had at least two Presidents, three Project Directors, and two Commercial Directors. Shaw was acquired by CB&I, and has had comparable turnover, with five Commercial Directors, two Project Directors and two Construction Managers.

Before reviewing the relevant events, we wish to share with you our view that the management turnovers have been accompanied by a change in attitude. Senior managers who began the project appeared to appreciate the significance of the task to our customers and to the nuclear community at large, and exhibited a commensurate dedication. Events indicate that this has been replaced by a different attitude, one that is less focused and seems intent on taking advantage of our cooperative nature.

We should also mention that we have noted the evident deterioration of the relationship between senior management at Westinghouse and Shaw/CB&I. Repair of that relationship will likely be necessary if you are to satisfy our concerns. As a Consortium, the two firms are jointly and severally liable to us. It does not matter to us which of you caused a specific problem. We look to both of you to remedy all the Consortium's deficiencies.

We regret that this letter is necessary and regret its length. Your poor performance has made both necessary. A complete description of our grievances would make this letter even longer. Consequently, we have chosen to focus on the events and issues concerning the structural modules, primarily CA-20 and CA-01, as well as certain design issues, and their combined effect on the expected completion date and cost of the project. We selected these examples to illustrate our dissatisfaction. They are not an exhaustive listing of your every shortcoming.

I. <u>THE EPC AGREEMENT ESTABLISHED THE PROJECT SHEDULE</u>

The EPC Agreement stated the Consortium's commitment to meet following dates for Unit 2:

Activity	Unit 2
CA-20 On-Hook	November 18, 2011
CA-01 On-Hook	March 29, 2012
Guaranteed Substantial Completion	April 1, 2016

To meet these dates, it was essential that the Consortium timely complete module fabrication, delivery, and assembly. The Consortium selected Shaw Modular Solutions, LLC ("SMS"), an affiliate of the Consortium, as the module fabricator. Problems with SMS's work began almost immediately. The NRC attempted to inspect the SMS facility between January 10 and 12, 2011, but the inspection had to be "terminated early because of the current status of activities at SMS." To the NRC's apparent surprise, SMS had not yet made enough progress to make an inspection worthwhile.

By letter dated February 22, 2011, SMS advised the NRC of its expectations for module production and shipment, as follows:

> SMS expects to be at a high level of production of structural modules in early June 2011. SMS expects that shipment of the first structural sub-module will occur the end of June 2011. ... If schedule changes are necessary, SMS will promptly notify the NRC.

SMS did not meet these module production and shipment dates. We are unaware if it gave the NRC the promised notice of these failures.

The NRC returned to inspect the SMS site between November 14 and 18, 2011. That inspection led to a "Notice of Nonconformance," dated January 6, 2012, based on deficiencies in SMS's quality assurance program. The Notice of Nonconformance stated:

> During this inspection, the NRC inspection team found that the implementation of your quality assurance program failed to meet certain NRC requirements which were contractually imposed on you by your customers or NRC licensees. Specifically, the NRC inspection team determined that SMS was not fully implementing its quality assurance program in the areas of training, design control, procurement document control, control of special processes, control of measuring and test equipment, control of nonconforming items, and corrective actions consistent with regulatory and contractual requirements, and applicable implementing procedures.

II. THE AUGUST 6, 2012 AGREEMENT CHANGED THE GUARANTEED SUBSTANTIAL COMPLETION DATES

By July 7, 2012, only 21 of 72 CA-20 sub-modules had been delivered to the site. Despite the poor progress, you assured us that you had resolved the module production problems. This led to the Agreement of August 6, 2012.

The 2012 Agreement recites that it resolved several pending change order requests. An additional motivation for us was to enable you to put the past module issues behind you and have a fresh start. Section IV.A of that agreement established the following revised guaranteed substantial completion dates:

Activity	Unit 2	Unit 3
Guaranteed Substantial Completion	March 15, 2017	May 15, 2018

After execution of the 2012 Agreement, you had no one to blame but yourselves for future module delays. Section IV.D of the 2012 Agreement made clear that future module delays would be your sole responsibility. It stated in pertinent part:

> Except as otherwise provided for in Article 9 of the EPC Agreement or Section XII.D of this Agreement, Contractor will not submit further Change Orders for any impacts to Project Schedule or Contract Price associated with Structural Module schedule delays and agrees that such further schedule delays will be the responsibility of Contractor.

Although the parties released certain claims against each other in the 2012 Agreement, Section XII.D of the agreement stated that our release did not apply to any claims "that may arise hereunder from Contractor's failure to deliver the Structural Modules referenced in Section III.C of this Agreement, so as to achieve" the revised Guaranteed Substantial Completion Dates.

The 2012 Agreement imposed on the Consortium certain additional scheduling obligations to enable us to monitor module progress. Section IV.D of that agreement stated:

> In order to measure impacts to the Project Schedule associated with Structural Module delivery, Contractor agrees to provide a detailed Structural Module delivery and assembly baseline schedule within 30 calendar days of the execution of this Agreement and to report actual progress against this schedule on at least a monthly basis.

The Consortium prepared the new baseline schedule for module delivery and assembly, as called for in this Agreement, but it has not provided the monthly progress reports.

In sum, the Consortium decided to engage SMS, an affiliated entity, as the module fabrication subcontractor. SMS proved to be neither equipped nor qualified to produce the modules. Nevertheless, in July 2012, we worked with you amicably by allowing you additional time that was made necessary, at least in part, by SMS's poor performance. In exchange, you agreed that you would not be entitled to any additional time extensions due to future module delays.

III. MODULE DELAYS CONTINUED AFTER THE 2012 AGREEMENT

Despite the Consortium's assurances, module production did not improve after the 2012 Agreement. The Consortium issued a module delivery and assembly baseline schedule, dated August 10, 2012, as called for in the 2012 Agreement. That schedule contained a series of milestone dates, including the following on-hook dates for CA-20 and CA-01:

Activity	Unit 2 Milestone Date
CA-20 On-Hook	January 19, 2013
CA-01 On-Hook	May 28, 2013

The Consortium has not met these on-hook dates or any other milestone dates in that schedule.

A. Module Status In September 2012

As of September 27, 2012, at least thirty of the milestone dates had already come and gone without completion of the associated milestone event. By that time, only 31 of the 72 sub-modules for CA-20 had been delivered to the site. As a result of the module production and delivery delays, we wrote to you on September 27, 2012. That letter stated:

> Due to the current status of the structural modules, the Owner remains concerned that the late fabrication, delivery, and installation of structural modules will impact the Consortium's ability to meet the critical path schedule date of January 28, 2013[1] (CA20 on-hook date), and eventually to meet the revised Unit 2 Guaranteed Substantial Completion Date (GSCD) and possibly the Unit 3 GSCD. The Owner requests the

[1] This date was incorrect. The letter should have referenced a January 19, 2013 CA-20 on-hook date.

> Consortium continue to provide structural module status updates during the weekly project review meetings and other status updates as previously agreed. Also, beginning no later than October 10, 2012, provide bi-weekly written status updates on the fabrication, delivery, and installation of the structural modules, including information on any structural module issues. Finally, the Owner requests the Consortium review with the Owner the Consortium's documented contingency plans concerning the structural modules prior to October 19, 2012. These contingency plans should include, at a minimum, actions to be taken by the Consortium to meet currently scheduled structural modules CA01-CA05 and CA20 on-hook dates and installation dates to support the Project schedule.

The Consortium did not comply with any of these requests.

As of September 2012, you had still not resolved your NRC issues. The NRC performed an unannounced inspection on September 10-14, 2012, which led to another "Notice of Nonconformance" arising out of deficiencies in SMS's quality assurance program. The NRC documented this in its letter of October 24, 2012, which stated:

> During the inspection, the inspectors found that the implementation of your QA program did not to meet [sic] certain NRC requirements imposed on you by your customers or NRC licensees. Specifically, SMS failed to promptly correct conditions adverse to quality and significant questions adverse to quality, failed to effectively implement a corrective action regarding documentation of late entries in a quality records procedure, failed to preclude recurrence of significant conditions adverse to quality related to identification and control of items, and failed to perform adequate corrective actions associated with a nonconformance identified during a previous NRC inspection.

Shortly after this, the NRC advised CB&I of a "chilled work environment" at the Lake Charles facility, which was causing employees to believe that they "are not free to raise safety concerns using all available avenues" and that "individuals have been retaliated against for raising safety concerns."

B. <u>Module Status In March 2013</u>

By March 6, 2013, only 40 of the 72 sub-modules for CA-20 had been received. At our request, a meeting to discuss module production was held among executive officers in Columbia on April 9, 2013. Westinghouse did not attend the meeting, but CB&I was there and it promised that the Consortium would deliver four modules in the second quarter of 2013, 40 modules in the third quarter, and 39 modules in the fourth quarter. It also informed us of a significant delay in the on-hook dates, as follows:

Activity	Delayed Unit 2 Date
CA-20 On-Hook	October 31, 2013
CA-01 On-Hook	September 4, 2014

The Consortium missed the revised CA-20 on-hook date of October 31, 2013 and, as of today, has yet to reach this milestone. The Consortium is also not on schedule to meet the revised CA-01 on-hook date of September 4, 2014.

C. Module Status In May 2013

By May 25, 2013, the Consortium had delivered only 41 of the 72 CA-20 sub-modules. And it had delivered only one of these in the preceding eleven weeks.

D. The Consortium Reported Schedule Delays In June 2013

On June 5, 2013, SCE&G publicly disclosed your statement to us that you would not be able to meet the required completion dates in the 2012 Agreement. We reported your estimate that completion of unit 2 would occur in either the fourth quarter of 2017 or the first quarter of 2018 and your estimate that completion of unit 3 would be "similarly delayed." Due to these delays, we also reported that SCE&G's 55% cost of the project could increase by $200 million. We noted that these schedule changes and cost increases resulted from "delays in the schedule for fabrication and delivery of sub-modules for the new units."

E. Module Status In July 2013

We saw no improvement over the next several months. By July 18, 2013, the Consortium had delivered only 44 of the 72 CA-20 sub-modules. This means that it had delivered only three modules in the preceding 11 weeks.

On August 7, we sent you another letter expressing our concerns about delays. On September 17, you advised us that, unless we objected, you would move the work of completing some CA-20 sub-modules from Lake Charles to the site. Your proposal was to move the uncompleted sub-modules into a temporary, onsite quarantine area to complete document processing and make minor repairs. We responded that we would not interfere with your decisions about how best to perform the work.

F. The Consortium Reported Further Schedule Delays In September 2013

On September 18, 2013, the executives of all involved companies met in Columbia. That meeting resulted in a September 25 letter from you, which included a schedule showing the following activities and dates:

Activity	Unit 2 Target Date	Unit 2 Late Date
CA-20 On-Hook	January 24, 2014	January 27, 2014
CA-01 On-Hook	July 18, 2014	September 18, 2014
Substantial Completion	December 15, 2017	December 15, 2017

Your letter also stated that:

> The Unit 2 CA01 sub-module delivery schedule is being reviewed to incorporate the latest information and will be transmitted to you by October 2, 2013. We have scheduled a management meeting on October 3, 2013, to review these deliverables with your team.

The promised October 2 letter and schedule showed that all CA-20 sub-modules would be delivered by November 4, and CA-01 sub-module shipments would extend between November 3, 2013 and July 18, 2014. The letter and schedule also introduced, for the first time, a CA-20 "minimum configuration" concept that we believe has the potential to further impede your ability to achieve timely project completion. This concept conflicts with the 2012 Agreement, and associated August 10, 2012 baseline schedule, which call for a complete (equipment loaded) CA-20 module to be set on its foundation by January 19, 2013.

Your October 2, 2013 letter went on to state:

> The Consortium is taking additional management measures to add certainty to this schedule. Resources have been added to engineering to reduce the backlog of E&DCRs and N&Ds and improve the turnaround time to disposition these items. Personnel from Lake Charles have been located at the V.C. Summer site to perform final inspections and document closeout. Resources have been added to the modules team to repair or rework any conditions identified on the sub-modules and prepare them for assembly. A daily Lake Charles Plan of the Day process has been implemented to drive schedule, elevate issues and resolve problems. Weekly CBI senior management review and monitoring of Lake Charles progress against the plan has been established. Milestone Managers are

being added to the site team to drive schedule and accountability for module assembly and placement. We believe that actions such as these will improve performance.

Although this letter does not amend the EPC Agreement or modify our commercial positions, we commit our support to the Project in achieving the schedules provided herein. We will maintain frequent and transparent communications with your staff to ensure that any significant change in schedule is raised and understood. We encourage SCANA to monitor our schedules and provide immediate feedback if they are not meeting your expectations.

Of the CA-20 sub-modules remaining to be delivered as of this date, seven were earmarked for delivery to the onsite quarantine area for completion of document processing and minor repairs. Those sub-modules were not ready to be incorporated into the construction.

Weekly module update calls began on October 14. By December, however, the level of participation by Consortium management had begun to wane. "Frequent and transparent" communications did not materialize, and we have not received "immediate feedback" when we have raised schedule issues.

In our letter of October 21, 2013, we stated:

You have represented that this schedule embodies the Consortium's realistic expectations concerning performance of Unit 2 work and its commitment to achieve Unit 2 substantial completion date by December 15, 2017.

We appreciate the Consortium's efforts in preparing these schedules and the Consortium's commitment to allocate additional resources and to perform as to achieve Unit 2 substantial completion by December 15, 2017. We must remind you, however, that the Consortium remains contractually committed to the dates for substantial completion stated in the July 11, 2012 Letter Agreement. As you correctly noted, the schedules in no way amend the Agreement. In the Letter Agreement, the parties agreed to a Unit 2 Guaranteed Substantial Completion Date of March 15, 2017, and a Unit 3 Guaranteed Substantial Completion Date of May 15, 2018.

G. <u>Design Deficiencies Came To Light During September 2013 On-Site Assembly</u>

On September 3, 2013, Westinghouse informed us that it had identified problems with the design of CA-04. The Consortium had planned to set that module on the Nuclear Island in September 2013, but it delayed that work because of the need to modify the concrete foundation. The foundation placement was then put on hold during the foundation redesign and associated procurement.

H. Module Status In December 2013

By December 4, 2013, all 72 CA-20 sub-modules had finally been delivered to the site, although 30 of them required documentation processing and repairs at the on-site quarantine area. The modification effort continued well into 2014.

On January 8, 2014, Westinghouse informed us that six Engineering and Design Coordination Reports (E&DCR) had to be completed before placement of CA-20. It also advised us that another sixteen E&DCRs would need to be completed after placement of CA-20, but before placement of wall concrete.

As of February 2014, none of the 47 CA-01 sub-modules had been delivered, although 20 should have been delivered by then, according to the October 2, 2013 schedule.

I. Module Status In March 2014

The Consortium has been providing our construction team with daily email updates relating to CA-20, but the updates continue to illustrate performance shortcomings. The March 11, 2014 email update reflected an on-hook date of March 31. The email updates of March 12 and 13 reflected the same date, but stated that such date was "in jeopardy" and pending management review. The March 14, 15, 17 and 18 email updates all reflected a date of April 7 for this activity. Those from March 20, 21, 22, 23, 25, 26 and 27 all stated that the April 7 date was "under review." Beginning on March 28, the email updates stated that the on-hook date had slipped again to May 10. In short, the projected on-hook date for CA-20 continues to slip and, by the end of March, we were farther away from completion of that activity than the Consortium had stated we were at the beginning of March.

The Consortium's progress with CA-01 has also been poor. Westinghouse has informed us that it is reviewing its design for that module and future changes could delay its placement. Due to these design issues, documentation approving placement of CA-01 is not expected until August 31, 2014.

IV. DESIGN ISSUES HAVE CONTRIBUTED TO THE PROJECT DELAY

A. IFC Design Delays

Other design issues, in addition to those identified above, have also delayed the project and are expected to contribute to future delays. Foremost among these is the delayed completion of Issued For Construction (IFC) drawings. The IFC percentage complete is the Consortium's primary metric for evaluating the status of design. That information shows that the Consortium has failed to meet expectations for design finalization and has misjudged its own performance.

The Consortium's early reports of design progress were optimistic. For example, in the March 17, 2011 Monthly Project Review minutes, the Consortium reported that it had delivered 90.49% of the scheduled IFC documents. As a result, the Consortium stated, "Design finalization is coming to an end and transitioning to support the Certified for Construction (CFC) design."

The May 19, 2011 Monthly Project Review minutes continued to reflect satisfactory progress. They reported Westinghouse's statement that design finalization was considered to be complete by the Department of Energy (DOE) and according to WEC's definition. The minutes also reported Westinghouse's estimate that the design was 95% complete. In addition, they reported Westinghouse's statement that the remaining engineering had been defined in a resource-loaded schedule, which it would use to monitor progress to completion.

The October 20, 2011 Monthly Project Review minutes reported Westinghouse's statement that site-specific engineering was winding down and that design finalization should be complete in the summer of 2012.

The Consortium began reporting design delays in May 2012, when you advised us that you would not meet the October 11, 2012 schedule for many of the IFC packages. On December 31, 2013, the Consortium reported to us that the IFC design documents were now only 94% complete. The Consortium continued this trend of revising design progress downward. On March 31, 2014, Westinghouse reported that the IFC documents were only 88% complete.

B. Design Issues Impact Nuclear Island Civil/Structural Work

Westinghouse's many design changes have also adversely impacted the Nuclear Island (NI) civil/structural work. One example concerns the A2 I wall in the Auxiliary

Building, which is a fairly simple reinforced concrete wall. Two of the construction packages are VS2-1210-COW-003 (rebar/embeds for I wall areas 4 and 5) and VS2-1210-CCW-001 (concrete for I wall areas 4 and 5). There were 109 unique E&DCRs between the two work packages. Ninety-two (92) of the E&DCRs were WEC initiated. This wall placement was delayed several weeks due to the design clarifications and changes.

C. **Design Issues Are Requiring Multiple License Amendment Requests**

The lack of WEC design maturity is evident in the high numbers of License Amendment Requests (LARs) and Departures to the Final Safety Analysis Report (FSAR) being submitted. As noted in the April 17, 2014 project status review meeting, 90 LARs have been identified; the NRC has approved 11 LARs; and 15 LARs are under NRC review. The following are three examples of these LARs and their importance:

- LAR 13-01/WEC LAR 54 (base mat shear reinforcement design spacing requirements) adversely impacted the schedule for Unit 2 nuclear island base mat concrete placement.

- LAR 13-02/WEC LAR 55 (base mat shear reinforcement design details revising the licensing basis from ACI 349 to ACI 318) also adversely impacted the schedule for Unit 2 nuclear island base mat concrete placement.

- LAR 14-01/WEC LAR 60 (Auxiliary Building structural details) has adversely impacted the schedules for construction of Auxiliary Building walls and floors and construction of structural module CA 20.

Furthermore, we anticipate that LAR 13-33/WEC LAR 53 (condensate return in the Containment Building) will impact construction progress. The same is true of LAR 14-07/WEC LAR 78 (CA04 tolerances); LAR 14-05/WEC LAR 72 – CA05; LAR 13-13/WEC LAR 02a (Turbine Building structural layout, which has been approved for Plant Vogtle); and LAR 13-14/WEC LAR 08 (Battery Room changes). We also anticipate that an LAR will be needed for coating thermal conductivity methods, which will impact Containment Vessel ring 1.

In addition to the LARs, the Consortium has also had a large number of Departures. The April 17, 2014 project status report states that 595 Departures have been identified. Of these 237 are in process and 358 are in the queue. These Departures do not require NRC review but have the potential for impacting the project schedule due to Westinghouse's design changes.

V. OUR FRUSTRATION CONTINUES TO MOUNT

As a result of these events, our frustration continues to mount. You have made promise after promise, but fulfilled few of them.

We are aware that the Consortium is in the process of preparing yet another re-baseline of the project schedule. We are entitled to a re-baseline schedule that reflects all mitigation measures reasonably possible to ensure completion of Units 2 and 3 on or near the currently projected completion dates. Please note that this statement of our rights is not an acceleration order. The currently projected completion dates are already past the dates to which the parties agreed in the 2012 Agreement. The delays since then have been solely the Consortium's fault. Thus, you are contractually obligated to take the steps necessary to mitigate the delays at your own expense.

Your unexcused delays will cause our project costs to increase greatly. We intend to hold you strictly to all provisions of the EPC Agreement and expect you to reimburse us for all our additional costs.

We have prepared a preliminary estimate of the added costs associated with your most recent completion projections, that is, completion of unit 2 in either the fourth quarter of 2017 or the first quarter of 2018 and a similar delay to completion of unit 3. Based on such delays, we estimate that we will incur about $150 million in additional site costs, and will be entitled to about $100 million in liquidated damages. If you fail to meet your most recent completion projections, these amounts will be even higher. We are in the process of investigating other additional costs that we are incurring due to the unexcused delays or associated changes to your work plan. We will advise you of their categories and amounts once we have completed our investigation.

Any future delays to those projections will require further adjustments to the payment schedules.

VI. CONCLUSION

It is imperative that the Consortium demonstrate a renewed commitment to this project. To help achieve that, we wish to discuss these performance deficiencies and associated delays with you, as well as the measures that you intend to take to mitigate the delays. We also wish to explore with you the extent to which the Consortium's unexcused project delays constitute breaches of material provisions of the EPC Agreement.

Respectfully,

Lonnie N. Carter
President & CEO Santee Cooper

Kevin B. Marsh
President & CEO SCANA

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Internal Memorandum

Date: March 11, 2013

From: Howard Axelrod, Energy Strategies Inc.

To: Sylleste Davis, Santee Cooper

Subject: Summary Report on Energy Strategy's VCS Marketing Activities

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Background

Santee Cooper is a co-owner with South Carolina Gas and Electric in the construction of two Westinghouse AP-1000 Advance nuclear power plants – V.C. Summer 2 & 3 (VCS). Each unit is capable of producing 1,117 MW of capacity for a total of 2,234 MW, enough to serve the electrical needs of over 230,000 customers. The planned start-up date is 2018 and 2019, respectively. The cost for these two plants has been estimated at $9.8 billion plus transmission and financing charges. Santee Cooper will own approximately 1,000 MW of the two power plants.

Between two to three years ago, Santee Cooper re-evaluated its generation expansion requirements and due, in part, to recessionary impacts of economic expansion and in part, to a loss of a major customer, revised its need for power (i.e. VCS) assessment which resulted in a reduction of approximately 500 MW of new generation in the forecasted planning horizon. At that point, Santee Cooper initiated a strategy to sell either 500 MW of VCS capacity or the equivalent output via long term purchase power agreements (PPA).

Over this three year period, Santee Cooper contacted a range of investor-owned, public power utilities and joint action agencies in the Southeast region of the United States. While several entities contacted indicated an interest to further pursue its investigation of the VCS offering, to date, only Duke Energy is in active negotiations with Santee Cooper with regards to the direct sale of VCS 2 & 3 assets [1] No other utility that was approached by Santee Cooper has indicated an interest in either an outright asset purchase or the execution of a long term PPA.

In 2012, Energy Strategies, Inc. was retained to assist in the development and execution of a strategic marketing plan for VCS. Four primary tasks were identified including:

1. Develop a comprehensive strategic marketing plan
2. Track and identify emerging opportunities and alternative marketing strategies
3. Perform in-depth analysis of potential candidates including the development of "buyer-specific" marketing presentations
4. Participate in and support Santee Cooper's upcoming strategic planning process as requested.

This report summarizes the findings and recommendations of this strategic marketing assessment. While the following two sections will outline our findings and recommendations (next steps). A highlight of the most significant observations is as follows:

- *Until VSC construction is complete, both plants are operational, and all costs are known with a high degree of certainty, it is unlikely, that any utility, albeit with few exceptions[2], would likely entertain such an asset acquisition unless the offering was significantly discounted to reflect the risks and uncertainties associated with a $10 billion ongoing project.*
- *There is a greater likelihood that a utility might engage in a short to intermediate term PPA for either VCS or a slice of the Santee Cooper system including VCS as part of the portfolio if the price was competitive. However, annual revenue requirements for VCS as*

[1] A separate internal marketing report being prepared by Sylleste Davis provides in greater detail the contacts and experiences of Santee Cooper's marketing efforts during this period.

[2] Duke and TVA are two feasible candidates for varying reasons. While Duke continues to negotiate with Santee, TVA has indicated that its position on nuclear expansion is in flux In order to rationally evaluate whether a given utility would be a serious candidate for a nuclear sale, we evaluated four criteria

- Need for base load generation within V. C. Summer planning horizon
- A "sophisticated" understanding of nuclear generation, i.e., ownership or PPA with other nuclear power projects
- Prior acceptance of minority interest in a major project
- Transmission access to V.C. Summer

Only Duke and TVA were ranked as Priority 1 having the greatest propensity to buy a portion of VCS.

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measured by its unit costs will be higher than currently available alternative sources of generation including a new combined cycle gas turbine. In order for Santee to offer a competitively priced PPA for VCS, would require, for a period of time, a measurable "discount" relative to VCS's embedded costs. Depending upon the forecasted assumptions, it could take over ten years before VCS's annualized costs are below competitive prices in the Southeast.

- *Nuclear power, especially newer units are currently viewed by its opponents as uneconomic and non-competitive with CCGTs. This misunderstanding of nuclear power economics is short sighted as it fails to consider future rising natural gas prices and the cost of carbon emissions whether in the form of a carbon tax or cap and trade protocol. Our studies found that there is a high probability that nuclear power can be economically advantageous to alternative state-of-the-art CCGT.*
- *Nuclear power, as a utility investment, especially for investor owned utilities, can be a double edged sword: on the one hand, its capital concentration adds risk to the company's balance sheet should regulators limit cost recovery, but on the other hand, the profits derived from a nuclear plant are projected to be between 5 to 8 times greater than that of a CCGT.[3] With limited opportunities for earnings growth, a nuclear investment can offer sizable contributions to earnings for an investor owned utility.*

[3] *Assuming that both nuclear and CCGT were economically equivalent (as measured by net present value of life cycle revenue requirements), the profits derived from a nuclear plant would be between 5 to 8 times greater than that of a CCGT.*

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Summary of Findings

Over the last several months I have been able to achieve a greater understanding of the dynamics of the Southeast markets, the changing shift from coal and nuclear to natural gas and the impact the economy has taken on load growth and ultimately on generation planning.

I have found that a number of my pre-conceptions as to utility risk aversion were validated. I also achieved a better appreciation for the conservative nature of public power – whether a stand-alone utility or a joint action agency, short term rate impacts and competitive positioning trumped longer term growth and earnings related objectives.

My investigation included in-depth discussions with executives and staff from The Energy Authority, Old Dominion, AMP Ohio, MEAG, Cogentrix (formerly a Goldman Sacks subsidiary) , and SERC The focus of these discussions was to ascertain not only their interest in buying nuclear energy or capacity, but what they, as industry leaders, understood as the benefits and pediments to such an acquisition. A sample of the content of our findings was as follows and is further discussed in Appendix A:

- For Old Dominion (Rick Beam, VP of Generation Planning and Supply), its Board of Trustees were adamantly opposed to any investment in a power plant with capital costs four times greater than other sources of generation.
- For AMP (Marc Gerkin, CEO), they would be glad to consider a VCS PPA, but it had to be cost competitive.
- For Cogentrix (John Gasbarro, Sr VP Asset Management), they would never consider such an investment unless it was accompanied by a long term PPA to buy back the electricity produced by the plant.

Finally, our analysis of several viable prospects using a ranking system discussed above, found that TVA was a Priority 1 candidate. TVA was an aggressive developer of nuclear power, had emphatically achieved the support of its Board of Trustees to retire coal units while planning to add some 7,000 MW of new nuclear generation over the next twenty years and was a leading supporter the next generation of small scale nuclear reactors. Yet, the meeting with TVA found

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that it had done a 180 as to nuclear. Part of the reason may have been the difficulties they faced in completing Watts Bar 2 or the fact that the new leadership team was reviewing and re-evaluating TVA's strategic business plans that had up until recently been focused on nuclear expansion.

My risk analysis of state-of-the-art advance nuclear design (AP1000) versus state-of-the-art combined cycle gas turbines revealed that under current conditions, namely:

- Natural gas prices are at their lowest levels in decades, with supplies rising at a faster pace than demand,
- The lack of a comprehensive national carbon dioxide regulation that was expected to include a carbon tax or cap and trade mechanism,
- A lackluster recovery of the US and Southeast economies,
- The continued decline in the correlation between growth in GNP and the growth in electric demand, due in part to shifts in consumption patterns, energy efficiency, and a loss of more energy intensive industries to China and Mexico,

there is a definite economic advantage to CCGT over nuclear measured in both annual levelized unit costs and net present value (NPPV) of life cycle revenue requirements. The capital cost of the CCGT is a quarter of a nuclear plant, the time to plan through construction is also one quarter, and a reasonably economical size can be as low as 300 MW to better match load growth. My study shows that under these conditions, there is an 80%+ chance that even under a range of conditions the NPPV of a CCGT will be less than that of a new nuclear plant

However, this same study shows that minor, but highly realistic changes in a few key areas will reverse this finding.

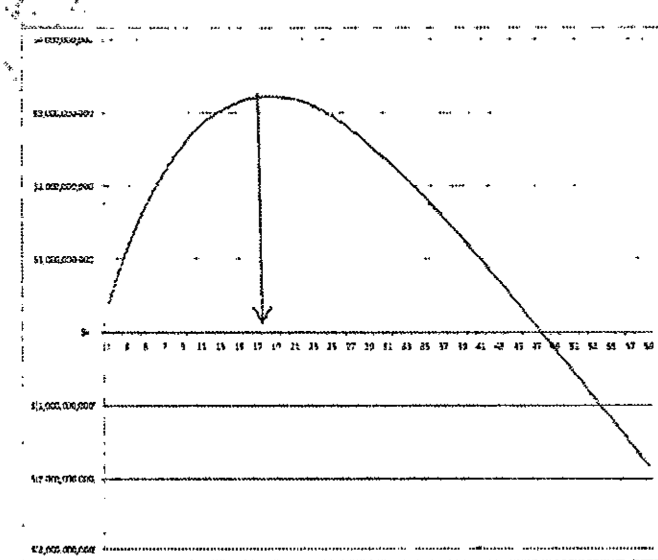
Natural gas prices, while still at historical lows, have increased by nearly half this year. The rational for adding more drilling rigs is finally seeing a diminishing trend as not only supply has outstripped demand, but storage capabilities have been maxed out. With global demand for natural gas expected to continue, surplus gas planned to be exported as LNG, and environmental controls imposed on shale gas developers, natural gas prices will likely rise. The recently released 2013 EIA long range energy outlook projects natural gas prices to be 20% greater than the 2012 forecast for the same forward years.

During the early to mid-2000 period, there was a political push for Congress to impose a carbon tax on power plant CO_2 emissions. The range of expectations was between \$10 to \$20 per ton beginning in 2010. While a costly measure, environmentalists argued that CO_2 abatement would cost far more - up to \$80 per ton. With the recession emerging and continued scientific debate over the causes of global warming, no legislation was passed. However, there is a renewed debate over the need for CO_2 control. The President has promised that during his current term, he would impose administrative measures if Congress would not pass such a bill.

Modest increases in CCGT costs caused by slightly higher natural gas prices and a moderate fee for CO_2 emissions would shift the economic comparison where there is over 84% chance that the nuclear NPV is less than CCGT.

Until electric demand begins to rise and/or as utilities begin to retire older, less efficient coal fired generation, it will take several years before utility planners begin to seriously evaluate the long term benefits of nuclear vis-à-vis CCGT.

As the economic pendulum swings to nuclear power, the sale of VCS may continue to pose a financial dilemma for many utility systems especially, public power. As discussed above, for both investor-owned and public power, a nuclear power plant's capital costs can strain either type of utility's balance sheet, and more significantly raise the ire of consumers, politicians and nuclear opponents if retail rates are forced to rise.



Under one of our case studies where nuclear power has over an 83% chance of being less costly

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than CCGT, in terms of NPV, it would still take over 18 years before annual revenue requirements would be less than CCGT. The accompanying chart provides an illustration of how long it would take to reach the point when a nuclear's annual cost was less than a comparable CCGT.

For a municipal electric system, the ability to either pass through higher costs or defer such charges until a later date when nuclear costs are less than market prices, raises a significant barrier.

For a large investor-owned utility, this issue can be mitigated as the cost of this added nuclear generation is averaged against other sources of cost generation in its portfolio. Rates could further be level out by employing a rate base phase-in plan. Most importantly, however, from an investor's perspective, an economically equivalent nuclear plant can produce up to eight times the amount of earnings vis-à-vis a CCGT.

Proposed Next Steps

Summary

- Focus on designing a market based PPA for VCS recognizing that the price may not recover all of VCS' costs, especially during the first ten years of operation.
- Evaluate the feasibility of a deferred revenue deficiency account that would track and record bypassed revenues, the difference between VCS' embedded costs and revenues.
- Explore the use of financial derivatives such as contracts for differences and collars to supplement the PPA in order to offset uncertainty in exchange for fixed prices.
- Solicit interest for 5 – 10 year PPA's at prices competitive with projected regional avoided costs.
- Track Ohio's unique renewable portfolio standard that promises to offer monetary credits for advanced nuclear generation. Values as high as $20 per ton of displaced CO_2 have been cited.

With the possible exception of Duke, it is unlikely that any utility in the Southeast would consider acquiring a portion of VCS until a high level of uncertainty as to ultimate capital cost and construction completion is achieved. Over the next five years; however, the marketability of VCS could be far more favorable as:

- Budget and scheduling milestones are met
- Natural gas prices begin to rise (as predicted by the EIA in its 2013 Long range Energy Outlook)
- Carbon emissions are addressed by Congress or the EPA.
- Economic recovery accelerates

It is further assumed that Santee Cooper, for statutory reasons, cannot discount the cost of its portion of the VCS plants being sold to reflect scheduling and budgeting risks. Otherwise, Santee could auction the plant to the highest bidder and then write-off the difference. As a result, the asset sale of VCS, may have to wait until the above mentioned conditions improve.

On the other hand, a market oriented and well-crafted PPA could be a viable transitional tool that would mitigate the cost of carrying VCS especially during the initial start-up years As noted earlier, VCS annualized costs will go through three stages:

1. The initial period where annual costs are greater than market based prices and as such, sales at market based prices will result in an accrual of deferred cost recovery account.
2. An intermediate period where VCS costs are below market prices, and the excess is used to "pay down" the deferred cost account.
3. A final period where VCS costs are substantially below market prices and the reserve account is closed.

During the initial period, even as VCS' annualized costs are above market prices, its variable costs should be well below market prices and as such, any sales at market will cover variable costs as well as a contribution to fixed costs, namely, depreciation, interest charges, and any reserve accounts including decommissioning expenses.

It appears as if it will take more than ten years before market prices will exceed VCS embedded costs and as a result, the deferred account will continue to grow although at a diminishing rate. Santee could limit its "losses" by indexing the PPA's annual adjustments to external indices that have the highest likelihood of exceeding the expected escalation rate of regional wholesale electric prices.

Santee could mitigate its losses by offering a PPA for a slice of the system including VCS as opposed to VCS as a dedicated offering. While reducing the size of the deferred account, it also lowers the amount of VCS under contract

Santee could also mitigate market price volatility by procuring financial instruments that would serve to swap price uncertainty for fixed payments. Such instruments might include contracts for differences or collars. These financial instruments would not be linked to the actual PPAs, but serve as "side bets" which limit Santee's exposure to declining market driven prices.

Finally, we need to closely track Ohio's renewable portfolio standard which broadens the definition of renewable resources to include advanced technologies including the Westinghouse AP1000 advance nuclear design. Credits would be received for avoided carbon emissions To date, this facet of the program has not been fully implemented and additional legislation is pending that would enhance this unique program. With AMP Ohio considering joining the TEA team, the prospects for CNS sales into Ohio could be prove viable if the value of the credits exceeded $20/ton which would translate into about $20/MWH of displaced coal generation and $10/MWH for simple cycle gas turbines.

Concluding Comments

The VCS plants will someday be a valuable asset for Santee Cooper. By the time these plants are operational, it is more than likely that any rational assessment comparing base load nuclear to coal or CCGT would demonstrate the economic and environmental advantage of VCS

Santee Cooper has assumed significant risk in its acquisition of 45% of the two VCS plants. While, at the moment, it is too early to extract any real value from the investment, there will be a time when VCS will be a low cost provider of electricity. For Santee to sell a portion of its ownership in VCS now or in the near future, even at a price equal to its accumulated total costs, would fail to recover the value of the risk it has assumed in obtaining a license to construct a state-of-the-art set of nuclear plants or the value of future opportunities to either provide its own customer base with low cost, low emitting generation or the ability to sell this energy at a market price above embedded costs.

Financial considerations will dictate what Santee will need to do; however, if at all possible, a marketing strategy that focuses on purchase power agreements will preserve Santee's options for the future.

Appendix A

Interview Notes

The following are my summary notes of conversations on V. C. Summer sales opportunities and barriers. On December 5, I interviewed Rick Bean, Vice President of Generation and Supply at Old Dominion. On December 10, Mike Cool and I met with TEA staff members Dave McCue, Mike Trobaugh and Jim Richardson. On January 4, I met with AMP CEO Marc Gerkin and Jolene Thompson, Sr. VP Member Services & External Affairs.

ODEC

Rick indicated that there little or no chance that ODEC would be interested in an ownership share of V. C. Summer. He also was not optimistic about a long term PPA. He stated the following reasons:

- Concerned over adequacy of firm transmission from ODEC to V. C. Summer
- ODEC did evaluate nuclear but its Board was concerned over capital intensity and impact on balance sheet
- ODEC still schedules generation through the PJM
- After detailed resource review, ODEC is planning to build a CCGT. If not build, it will consider having another entity build and then execute a long term PPA
- Rick noted that Dominion (Virginia Power) has already approached ODEC for additional ownership of North Anna, which ODEC owns 11.6% (208MW)
- He also noted that Dominion was also looking to offload or retire nuclear generation in Wisconsin (Kewaunee).

TEA

The following areas of inquiry were provided to TEA and used as the basis for our two hour meeting:

1. Transmission congestion and reliability constraints in southeast

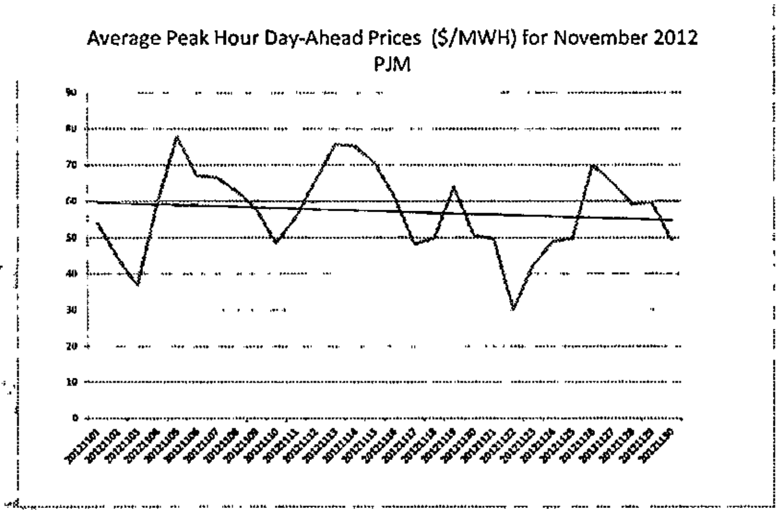
2. Access to markets in Florida, MISO and PJM – potential barriers and opportunities

3. Identified need for power opportunities know to TEA

4. Any insights on Ohio's Alternative Energy Portfolio Standard

Generally, I found the following comments the most interesting:

1. Transmission throughout the southeast should not be a major problem, although the cost of wheels through Southern ($5) was slightly more than Duke ($4). Wheels through Entergy; however, could be costly.
2. While scheduling into the PJM ISO is feasible; capacity credit would be minimal, if any at all. While real time price would be the last price cleared, peak hour clearing prices averaged below $60/MWH in November and similarly so in August, 2012. Off Peak prices averaged below $30/MWH.



Furthermore, energy-only contracts, without installed capacity credit, would likely to be for only shorter term durations of three years or less. Most load serving entities in the PJM are limited by their respective regulatory commissions to short and intermediate term conditions. Independent power suppliers serving the competitive retail markets would unlikely be able to

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commit the collateral requirements associated with long term PPAs. Finally, there are few large muni or coop systems in New Jersey and Pennsylvania, excluding AMP Ohio.

3. TEA staff suggested the following potential opportunities:

- Progress South (Florida) : TEA staff emphasized the potential opportunity with Progress South. Its Crystal River nuclear plant has been shut down since the fall of 2009 and could cost the company over $2.5 billion in repair and replacement power costs. The company has also spent over $1 1 billion on its new Levy County nuclear plant that is expected to cost an unbelievable $24 billion with completion by 2024. (I need to re-check this, but it is a figure reported by the Florida PSC.) Under a liberalized rate recovery mechanism, Progress has already collected from customers $750 million.

  TEA's thoughts were that if Levy County was mothballed, the $750 could be far better served buying a piece of V. C. Summer. Finally, I found that the company has projected that if Crystal River does not return to service by 2017, over 70 percent of its electrical generation will come from natural gas plants.

- Georgia Power: Apparently the Georgia Public Service Commission rejected a Georgia Power proposal to sign two long term PPAs based on its most recent IRP plan. I could not find any reference to this PSC decision and did not want to contact Southern or GPC at this point in time. However, there may be an opportunity to negotiate such a replacement deal with GPC; although I would think they will need to issue a new RFP. I will contact TEA after the New Year's to get more information as I have spent considerable time checking the Ga PSC dockets with no success. If TEA is correct, I have a very close relationship with Jeff Burleson. Jeff was the Director of Resource Planning at GPC, just prior to being promoted to VP System Operations for Southern Company. (Just a note of interest: I believe that Jeff's wife Pat, was Kim Green's (now at TVA) secretary when she was at Southern – small world.)
- EDF: Rumor has it that EDF (Électricité de France S.A.) is on the prowl for base load generation, possible including nuclear, in the Southeast. I am checking for a contact we might approach.

- AMP Ohio: TEA also noted that AMP Ohio might be a good candidate for VC Summer. However, no specifics were offered. I did not elaborate as Santee is already in discussions with AMP.
- Alabama Municipal Electric Authority: Reiterated what we know, that AMEA has the ability under its new PPA with Alabama Power to reduce its commitment for other sources of generation. While, ownership in VC Summer was not viewed as likely, a long term PPA is possible if the price is right. Transmission through the Southern system would add about $5.
- Piedmont Municipal Power Agency: with its 25% ownership in Catawba Nuclear, PMPA was a "natural" that was mentioned by TEA. I would think that PMPA has been contacted by Santee.
- Power South (Alabama & western Florida): Power South is a G&T coop serving some 20 distribution utilities in Alabama and Florida. PS owns approximately 2,000 MW of generation including: a 556 MW coal plant needing environmental upgrades (Lowman). PS also has an 8.16% interest in Alabama Power's 2,000 MW Miller coal station, but no ownership interest in nuclear and a very small piece of hydro (8 MW). Their generation portfolio could be at significant risk of price uncertainty with emerging carbon taxes and heavy metals regulations as well as rising natural gas prices.
- Reedy Creek (Disney): Reedy Creek was mentioned a remote possibility as it is in need of generation; however, TEA was not sure if nuclear would be cost effective.

<u>AMP Ohio</u>

On January 3 -4, I had meetings with Marc Gerkin and his senior management team at the request of Bob Dyer who has been retained by AMP to review its internal risk management practices and procedures. I informed Marc of my role at Santee and had an opportunity to privately discuss AMP's potential interest in renewing its consideration of a VCS procurement. Bottom-line, Marc felt the prior offering was just too high, but would re-consider if a more attractive offer could be made.

I also asked Marc if someone at AMP could help me understand and facilitate interest in VCS, as an advanced nuclear technology, in response to the more innovative Ohio Renewable Portfolio Standard that offers RECs for certain advanced technologies including the AP1000. Marc asked Jolene to help me and we are scheduled to have more detailed discussions this or next week. What I did learn was:

- The advance technologies goals have yet to kick in, but were specifically designed to encourage advanced coal and nuclear technologies
- Currently, the more typical RPS, has had limited success and RECs have declined from a high range in the $20s/MWH to currently below $5. There is, however, a legislative initiative to kick-start the process and get the REC prices up.
- The apparent reason for Ohio's unique advanced technology RPS was the SMR (small modular reactor) being developed by one of Ohio's larger manufactures (B&W?). With goals set for early 2020's, there is not likely to be a commercial SMR and VCS could be a very viable choice.
- There does not appear to be any geographic restrictions to the location of the advanced technology – i.e., it can be located outside of Ohio.
- Using VCS as the State's first advanced technology application might require both utility and political support including a push from the Governor's office.
- The most likely candidate is First Energy. Duke, like in South Carolina is impossible to work with
- Finally, while AMP is exempt from the RPS regulations, they can accrue and sell RECs.

ENERGY STRATEGIES, INC.

The V.C. Summer Strategic Marketing Plan

Summary Report

Prepared by: Howard Axelrod, PhD

Background

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2. Track and identify emerging opportunities and alternative marketing strategies

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3. Perform in-depth analysis of potential candidates including the development of "buyer-specific" marketing presentations
4. Participate in and support Santee Cooper's upcoming strategic planning process as requested.

This report summarizes the findings and recommendations of this strategic marketing assessment. While the following two sections will outline our findings and recommendations (next steps). A highlight of the most significant observations is as follows:

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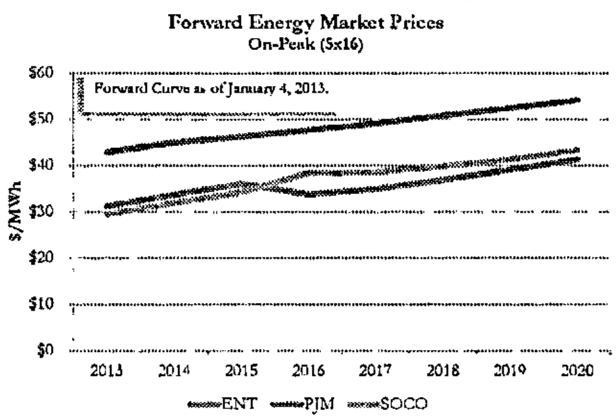
- *There is a greater likelihood that a utility might engage in a short to intermediate term (5-10 years) PPA for either VCS or a slice of the Santee Cooper system including VCS as part of the portfolio if the offering price was regionally price competitive. However, annual revenue requirements for VCS as measured by its unit costs will be higher than currently available*



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- Need for base load generation within V. C. Summer planning horizon
- A "sophisticated" understanding of nuclear generation, i.e., ownership or PPA with other nuclear power projects
- Prior acceptance of minority interest in a major project
- Transmission access to V.C. Summer

Only Duke and TVA were ranked as Priority 1 having the greatest propensity to buy a portion of VCS.

alternative sources of generation including a new combined cycle gas turbine. Projected regional forward peak load prices remain at or below $50/MWh[3] through the end of the decade, which is significantly less than the embedded cost of a new nuclear plant estimated at over $100/MWh. In order for Santee to offer a competitively priced PPA for VCS, would require, for a period of time, a measurable "discount" relative to VCS's embedded costs. Depending upon the forecasted assumptions, it could take over ten years before VCS's annualized costs are below competitive prices in the Southeast.

- *Nuclear power, especially newer units are currently viewed by many power system analysts as uneconomic and non-competitive when compared to state-of-the-art CCGTs. This view of nuclear power economics appears short sighted as it fails to consider future rising natural gas prices and the cost of carbon emissions whether in the form of a carbon tax or cap and trade protocol. Our studies found that there is a high probability that nuclear power can be economically advantageous to alternative state-of-the-art CCGT.*
- *Nuclear power, as a utility investment, especially for investor owned utilities, can be a double edged sword: on the one hand, its capital concentration adds risk to the company's balance sheet should regulators limit cost recovery, but on the other hand, the profits derived from a nuclear plant are projected to be between 5 to 8 times greater than that of a CCGT.[4] With limited opportunities for earnings growth, a nuclear investment can offer sizable contributions to earnings for an investor owned utility.*
- *As a result, while the perceived risks associated with the cost and duration of the nuclear construction cycle is considered extremely high, the earnings potential aspect of such a capital intensive investment can be a very attractive investment once the plants are operational.*

[3] Source: Provided to Sylleste Davis by Mike Cool

[4] *Assuming that both nuclear and CCGT were economically equivalent (as measured by net present value of life cycle revenue requirements), the profits derived from a nuclear plant would be between 5 to 8 times greater than that of a CCGT.*

Summary of Findings

Over the last several months I have been able to achieve a greater understanding of the dynamics of the Southeast markets, the changing shift from coal and nuclear to natural gas and the impact the economy has taken on load growth and ultimately on generation planning.

I have found that a number of my pre-conceptions as to utility risk aversion were validated namely, that nuclear power is a high cost investment and as long as natural gas prices remain low, i.e., below $5/mmbtu, CCGT will be considered the preferred choice of new generation. I also achieved a better appreciation for the conservative nature of public power – whether a stand-alone utility or a joint action agency, short term rate impacts and competitive positioning trumped longer term growth and earnings related objectives.

My investigation included in-depth discussions with executives and staff from The Energy Authority, Old Dominion, AMP Ohio, MEAG, Cogentrix (formerly a Goldman Sacks subsidiary) , and SERC. The focus of these discussions was to ascertain not only their interest in buying nuclear energy or capacity, but what they, as industry leaders, understood as the benefits and pediments to such an acquisition. A sample of the content of our findings was as follows and is further discussed in Appendix A:

- For Old Dominion (Rick Bean, VP of Generation Planning and Supply), its Board of Trustees were adamantly opposed to any investment in a power plant with capital costs four times greater than other sources of generation.
- For AMP (Marc Gerkin, CEO), they would be glad to consider a VCS PPA, but it had to be cost competitive.
- For Cogentrix (John Gasbarro, Sr VP Asset Management), they would never consider such an investment unless it was accompanied by a long term PPA to buy back the electricity produced by the plant.

Finally, our analysis of several viable prospects using a ranking system discussed above, found that TVA was a Priority 1 candidate. TVA was an aggressive developer of nuclear power, had emphatically achieved the support of its Board of Trustees to retire coal units while planning to add some 7,000 MW of new nuclear generation over the next twenty years and was a leading supporter the next generation of small scale nuclear reactors. Yet, Santee's meeting with TVA found that TVA was in the process of re-evaluating its position on the role nuclear power will play in future generation expansion plans. Part of the reason may have been the difficulties they faced in completing Watts Bar 2 or the fact that the new leadership team was reviewing and re-evaluating TVA's strategic business plans that had up until recently been focused on nuclear expansion.

My risk analysis of state-of-the-art advance nuclear design (AP1000) versus state-of-the-art combined cycle gas turbines revealed that under current conditions, namely:

- Natural gas prices are at their lowest levels in decades, with supplies rising at a faster pace than demand,
- The lack of a comprehensive national carbon dioxide regulation that was expected to include a carbon tax or cap and trade mechanism,
- A lackluster recovery of the US and Southeast economies,
- The continued decline in the correlation between growth in GNP and the growth in electric demand, due in part to shifts in consumption patterns, energy efficiency, and a loss of more energy intensive industries to China and Mexico,

there is a definite economic advantage to CCGT over nuclear measured in both annual levelized unit costs and net present value (NPPV) of life cycle revenue requirements. The capital cost of the CCGT is a quarter of a nuclear plant, the time to plan through construction is also one quarter, and a reasonably economical size can be as low as 300 MW to better match load growth My study shows that under these conditions, there is an 80%+ chance that even under a range of conditions the NPPV of a CCGT will be less than that of a new nuclear plant.[5]

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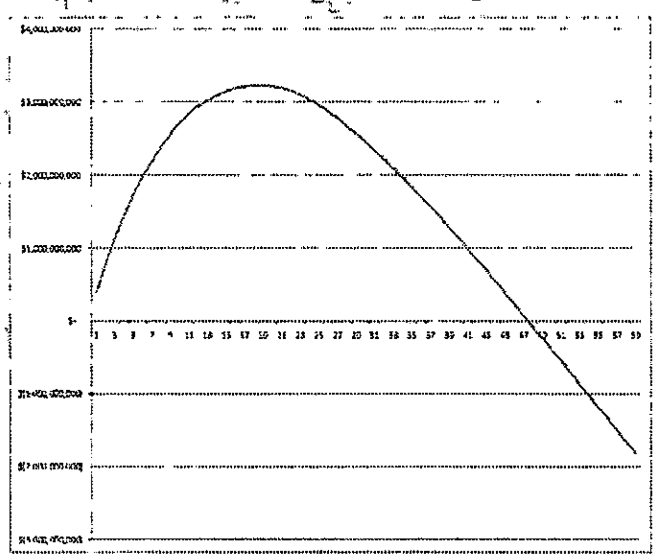
[5] In response to the competitive disadvantage of large scale nuclear power plants, a number of utilities and industry stakeholders have supported the commercialization of small modular reactor (SMR) design. At a target of 300 MW unit size, the SMR would compete with smaller scale CCGT. In April 2013, the 3[RD] Annual SMR Conference will be held and Howard Axelrod will attend on behalf of Santee Cooper. His goal will not only be to gain further

However, this same study shows that modest, but highly realistic changes in a few key inputs to the economic analysis will reverse this finding.

Natural gas prices, while still at historical lows, have increased by nearly fifty percent this year. The rational for adding more drilling rigs is finally seeing a diminishing trend as not only supply has outstripped demand, but storage capabilities have been stressed. With global demand for natural gas expected to continue, surplus gas planned to be exported as LNG, and environmental controls imposed on shale gas developers, natural gas prices will likely rise. The recently released 2013 EIA long range energy outlook projects natural gas prices to be 20% greater than the 2012 forecast for the same forward years.

During the early to mid-2000 period, there was a political push for Congress to impose a carbon tax on power plant CO_2 emissions. The range of expectations was between \$10 to \$20 per ton beginning in 2010. While a costly measure, environmentalists argued that CO_2 abatement would cost far more - up to \$80 per ton With the recession emerging and continued scientific debate over the causes of global warming, no legislation was passed. However, there is a renewed debate over the need for CO_2 control. The President has promised that during his current term, he would impose administrative measures if Congress would not pass such a bill.



Modest increases in CCGT costs caused by slightly higher natural gas prices and a moderate fee for CO_2 emissions would shift the economic comparison where there is over 84% chance that the nuclear NPV is less than CCGT.

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insights into the progress of SMR deployment, but to identify potential utility candidates who are interested in nuclear expansion regardless of whether it is a standalone SMR or a share of VCS.

Until electric demand begins to rise and/or as utilities begin to retire older, less efficient coal fired generation, it will take several years before utility planners begin to seriously evaluate the long term benefits of nuclear vis-à-vis CCGT.

As the economic pendulum swings to nuclear power, the sale of VCS may continue to pose a financial dilemma for many utility systems especially, public power. As discussed above, for both investor-owned and public power, a nuclear power plant's capital costs can strain either type of utility's balance sheet, and more significantly raise the ire of consumers, politicians and nuclear opponents if retail rates are forced to rise. Under one of our case studies where nuclear power has over an 83% chance of being less costly than CCGT, in terms of NPV, it would still take over 18 years before annual revenue requirements would be less than CCGT. The accompanying chart provides an illustration of how long it would take to reach the point when a nuclear plant's annual cost was less than a comparable CCGT.

For a municipal electric system, the ability to either pass through higher costs or defer such charges until a later date when nuclear costs are less than market prices, raises a significant barrier, although, not insurmountable.

For a large investor-owned utility, this issue can be mitigated as the cost of this added nuclear generation is averaged against other sources of cost generation in its portfolio Rates could further be level out by employing a rate base phase-in plan where the accrued capital costs including financing during construction, are staggered into rate base over a specified time period. Most importantly, however, from an investor's perspective, an economically equivalent nuclear plant can produce up to eight times the amount of earnings vis-à-vis a CCGT.

Proposed Next Steps

Summary

- Focus on designing a market based PPA for VCS recognizing that the price may not recover all of VCS' costs, especially during the first ten years of operation.
- Evaluate the feasibility of a deferred revenue deficiency account that would track and record bypassed revenues, the difference between VCS' embedded costs and revenues.
- Explore the use of financial derivatives such as contracts for differences and collars to supplement the PPA in order to offset uncertainty in exchange for fixed prices.
- Solicit interest for 5 – 10 year PPA's at prices competitive with projected regional avoided costs.
- Utilize the knowledge base and expertise of The Energy Authority (TEA) to assist and support Santee's development of a competitive PPA offering. TEA could provide support in the price discovery process of competitive PPAs in the Southeast, the MISO and the PJM regions. TEA's hedging and risk management capabilities could also be useful in designing a financial hedging strategy to limit Santee's price uncertainty exposure in fixing a PPA's price schedule
- Track Ohio's unique renewable portfolio standard that promises to offer monetary credits for advanced nuclear generation. Values as high as $20 per ton of displaced CO_2 have been cited.

With the possible exception of Duke, it is unlikely that any utility in the Southeast would consider acquiring a portion of VCS until a high level of uncertainty as to ultimate capital cost and construction completion is achieved. Over the next five years; however, the marketability of VCS could be far more favorable as:

- Budget and scheduling milestones are met
- Natural gas prices begin to rise (as predicted by the EIA in its 2013 Long range Energy Outlook)

- Carbon emissions are addressed by Congress or the EPA.
- Economic recovery accelerates

It is further assumed that Santee Cooper, for statutory reasons, cannot discount the cost of its portion of the VCS plants being sold to reflect scheduling and budgeting risks. Otherwise, Santee could auction the plant to the highest bidder and then write-off the difference. As a result, the asset sale of VCS, may have to wait until the above mentioned conditions improve.

On the other hand, a market oriented and well-crafted PPA could be a viable transitional tool that would mitigate the cost of carrying VCS especially during the initial start-up years. As noted earlier, VCS annualized costs will go through three stages:

1. The initial period where annual costs are greater than market based prices and as such, sales at market based prices will result in an accrual of deferred cost recovery account.
2. An intermediate period where VCS costs are below market prices, and the excess is used to "pay down" the deferred cost account.
3. A final period where VCS costs are substantially below market prices and the reserve account is closed.

During the initial period, even as VCS' annualized costs are above market prices, its variable costs should be well below market prices and as such, any sales at market will cover variable costs as well as a contribution to fixed costs, namely, depreciation, interest charges, and any reserve accounts including decommissioning expenses.

It appears as if it will take more than ten years before market prices will exceed VCS embedded costs and as a result, the deferred account will continue to grow although at a diminishing rate. Santee could limit its "losses" by indexing the PPA's annual adjustments to external indices that have the highest likelihood of exceeding the expected escalation rate of regional wholesale electric prices.

Santee could further mitigate its losses by offering a PPA for a slice of the Santee system including VCS as opposed to VCS as a standalone offering. Parenthetically, while reducing the size of the deferred account, it also lowers the amount of VCS under contract.

Santee could also manage market price volatility by procuring financial instruments that would serve to swap price uncertainty for fixed payments. Such instruments might include contracts for differences or collars. These financial instruments would not be linked to the actual PPAs, but serve as "side bets" which limit Santee's exposure to declining market driven prices. It is highly recommended that Santee call upon TEA for its expertise on risk management and hedging to support the development of this strategy.

Finally, we need to closely track Ohio's renewable portfolio standard which broadens the definition of renewable resources to include advanced technologies including the Westinghouse AP1000 advance nuclear design. Credits would be received for avoided carbon emissions. To date, this facet of the program has not been fully implemented and additional legislation is pending that would enhance this unique program. With AMP Ohio considering joining the TEA team, the prospects for REC sales into Ohio could prove a potential opportunity if the value of the credits exceeded $20/ton which would translate into about $20/MWH of displaced coal generation and $10/MWH for simple cycle gas turbines. While AMP Ohio might be an excellent conduit for these sales, the primary utility in Ohio would be FirstEnergy.

Concluding Comments

The VCS plants will someday be a valuable asset for Santee Cooper. By the time these plants are operational, it is more than likely that a rational assessment comparing base load nuclear to coal or CCGT would demonstrate the economic and environmental advantage of VCS.

Santee Cooper has assumed significant risk in its acquisition of 45% of the two VCS plants. While, at the moment, it is too early to extract any real value from the investment, there will be a time when VCS will be a low cost provider of electricity. For Santee to sell a portion of its ownership in VCS now or in the near future, even at a price equal to its accumulated total costs, would fail to recover the value of the risk it has assumed in obtaining a license to construct a state-of-the-art set of nuclear plants or the value of future opportunities to either provide its own customer base with low cost, low emitting generation or the ability to sell this energy at a market price above embedded costs.

Financial considerations will dictate what Santee will need to do; however, if at all possible, a marketing strategy that focuses on purchase power agreements will preserve Santee's options for the future.

Appendix A

Interview Notes

The following are my summary notes of conversations on V. C. Summer sales opportunities and barriers. On December 5, I interviewed Rick Bean, Vice President of Generation and Supply at Old Dominion. On December 10, Mike Cool and I met with TEA staff members Dave McCue, Mike Trobaugh and Jim Richardson. On January 4, I met with AMP CEO Marc Gerkin and Jolene Thompson, Sr. VP Member Services & External Affairs.

ODEC

Rick indicated that there little or no chance that ODEC would be interested in an ownership share of V. C. Summer. He also was not optimistic about a long term PPA. He stated the following reasons:

- Concerned over adequacy of firm transmission from ODEC to V. C. Summer
- ODEC did evaluate nuclear but its Board was concerned over capital intensity and impact on balance sheet
- ODEC still schedules generation through the PJM
- After detailed resource review, ODEC is planning to build a CCGT. If not build, it will consider having another entity build and then execute a long term PPA
- Rick noted that Dominion (Virginia Power) has already approached ODEC for additional ownership of North Anna, which ODEC owns 11.6% (208MW)
- He also noted that Dominion was also looking to offload or retire nuclear generation in Wisconsin (Kewaunee).

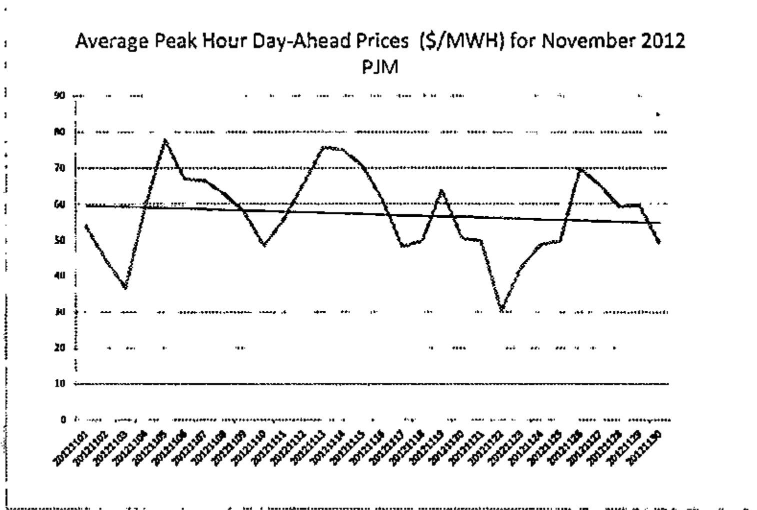
TEA

The following areas of inquiry were provided to TEA and used as the basis for our two hour meeting:

1. Transmission congestion and reliability constraints in southeast
2. Access to markets in Florida, MISO and PJM – potential barriers and opportunities
3. Identified need for power opportunities know to TEA
4. Any insights on Ohio's Alternative Energy Portfolio Standard

Generally, I found the following comments the most interesting:

1. Transmission throughout the southeast should not be a major problem, although the cost of wheels through Southern ($5) was slightly more than Duke ($4). Wheels through Entergy; however, could be costly.
2. While scheduling into the PJM ISO is feasible; capacity credit would be minimal, if any at all. While real time price would be the last price cleared, peak hour clearing prices averaged below $60/MWH in November and similarly so in August, 2012. Off Peak prices averaged below $30/MWH.



Furthermore, energy-only contracts, without installed capacity credit, would likely to be for only shorter term durations of three years or less. Most load serving entities in the PJM are limited by their respective regulatory commissions to short and intermediate term conditions.

Independent power suppliers serving the competitive retail markets would unlikely be able to commit the collateral requirements associated with long term PPAs. Finally, there are few large muni or coop systems in New Jersey and Pennsylvania, excluding AMP Ohio.

3. TEA staff suggested the following potential opportunities.

- Progress South (Florida) : TEA staff emphasized the potential opportunity with Progress South. Its Crystal River nuclear plant has been shut down since the fall of 2009 and could cost the company over $2.5 billion in repair and replacement power costs. The company has also spent over $1.1 billion on its new Levy County nuclear plant that is expected to cost an unbelievable $24 billion with completion by 2024. (I need to re-check this, but it is a figure reported by the Florida PSC.) Under a liberalized rate recovery mechanism, Progress has already collected from customers $750 million.

  TEA's thoughts were that if Levy County was mothballed, the $750 could be far better served buying a piece of V. C. Summer. Finally, I found that the company has projected that if Crystal River does not return to service by 2017, over 70 percent of its electrical generation will come from natural gas plants.

- Georgia Power: Apparently the Georgia Public Service Commission rejected a Georgia Power proposal to sign two long term PPAs based on its most recent IRP plan. I could not find any reference to this PSC decision and did not want to contact Southern or GPC at this point in time. However, there may be an opportunity to negotiate such a replacement deal with GPC; although I would think they will need to issue a new RFP. I will contact TEA after the New Year's to get more information as I have spent considerable time checking the Ga PSC dockets with no success. If TEA is correct, I have a very close relationship with Jeff Burleson. Jeff was the Director of Resource Planning at GPC, just prior to being promoted to VP System Operations for Southern Company. (Just a note of interest: I believe that Jeff's wife Pat, was Kim Green's (now at TVA) secretary when she was at Southern – small world.)

- EDF: Rumor has it that EDF (Électricité de France S.A.) is on the prowl for base load generation, possible including nuclear, in the Southeast. I am checking for a contact we might approach.
- AMP Ohio: TEA also noted that AMP Ohio might be a good candidate for VC Summer. However, no specifics were offered. I did not elaborate as Santee is already in discussions with AMP.
- Alabama Municipal Electric Authority: Reiterated what we know, that AMEA has the ability under its new PPA with Alabama Power to reduce its commitment for other sources of generation. While, ownership in VC Summer was not viewed as likely, a long term PPA is possible if the price is right. Transmission through the Southern system would add about $5.
- Piedmont Municipal Power Agency: with its 25% ownership in Catawba Nuclear, PMPA was a "natural" that was mentioned by TEA. I would think that PMPA has been contacted by Santee.
- Power South (Alabama & western Florida): Power South is a G&T coop serving some 20 distribution utilities in Alabama and Florida. PS owns approximately 2,000 MW of generation including a 556 MW coal plant needing environmental upgrades (Lowman). PS also has an 8.16% interest in Alabama Power's 2,000 MW Miller coal station, but no ownership interest in nuclear and a very small piece of hydro (8 MW). Their generation portfolio could be at significant risk of price uncertainty with emerging carbon taxes and heavy metals regulations as well as rising natural gas prices.
- Reedy Creek (Disney): Reedy Creek was mentioned a remote possibility as it is in need of generation; however, TEA was not sure if nuclear would be cost effective.

<u>AMP Ohio</u>

On January 3 -4, I had meetings with Marc Gerkin and his senior management team at the request of Bob Dyer who has been retained by AMP to review its internal risk management practices and procedures. I informed Marc of my role at Santee and had an opportunity to privately discuss AMP's potential interest in renewing its consideration of a VCS procurement.

Bottom-line, Marc felt the prior offering was just too high, but would re-consider if a more attractive offer could be made.

I also asked Marc if someone at AMP could help me understand and facilitate interest in VCS, as an advanced nuclear technology, in response to the more innovative Ohio Renewable Portfolio Standard that offers RECs for certain advanced technologies including the AP1000. Marc asked Jolene to help me and we are scheduled to have more detailed discussions this or next week. What I did learn was:

- The advance technologies goals have yet to kick in, but were specifically designed to encourage advanced coal and nuclear technologies.
- Currently, the more typical RPS, has had limited success and RECs have declined from a high range in the $20s/MWH to currently below $5. There is, however, a legislative initiative to kick-start the process and get the REC prices up.
- The apparent reason for Ohio's unique advanced technology RPS was the SMR (small modular reactor) being developed by one of Ohio's larger manufactures (B&W?). With goals set for early 2020's, there is not likely to be a commercial SMR and VCS could be a very viable choice.
- There does not appear to be any geographic restrictions to the location of the advanced technology – i.e., it can be located outside of Ohio.
- Using VCS as the State's first advanced technology application might require both utility and political support including a push from the Governor's office
- The most likely candidate is First Energy. Duke, like in South Carolina is impossible to work with.
- Finally, while AMP is exempt from the RPS regulations, they can accrue and sell RECs.

Study: New nuclear projects are uneconomic 'sunk costs'

SNL Power Daily with Market Report

March 15, 2013 Friday

Section: Exclusive

Length: 962 words

Byline: Matthew Bandyk

Highlight: Ratepayers in states in the Southeast where new nuclear reactors are being built or proposed would save money if the projects were simply abandoned in favor of efficiency and natural gas-fired generation, according to a new study.

Body

Ratepayers in states in the Southeast where new nuclear reactors are being built or proposed would save money if the projects were simply abandoned in favor of energy efficiency initiatives and natural gas-fired generation, according to a study from the Vermont Law School's Institute for Energy and the Environment, released March 14.

Even though billions have already been invested toward new nuclear plants in Georgia, South Carolina and Florida, writing off these costs and moving on without nuclear would be the most economic option, the study said. "You must not allow sunk costs to distort future choices," the institute's senior fellow for economic analysis, Mark Cooper, told reporters on a March 14 conference call. "When should you walk away from $1 billion or $2 billion in sunk costs? When continuing down the wrong path will waste $10 billion more."

According to Cooper's study, about $6 billion has been spent on reactors in the Southeast so far, and the proposed projects will cost $60 billion to $70 billion total. Any further investment would saddle ratepayers with unnecessary bill increases, Cooper said.

Cooper previously has described the "nuclear renaissance" as "mythical" and has opposed proposed cost recovery legislation in Iowa.

In this study, he focused on two projects in particular: the new units at the V.C. Summer plant, being built by SCANA Corp. subsidiary South Carolina Electric & Gas Co., or SCE&G, and South Carolina Public Service Authority d/b/a Santee Cooper; and the Levy County plant, proposed by Duke Energy Corp. subsidiary Florida Power Corp. d/b/a Progress Energy Florida.

In the case of Summer, SCE&G's own reported numbers show that in a base case scenario, the cost of electricity from a generation strategy focused on natural gas-fired, combined-cycle plants would be cheaper than the new reactors by $9.4 billion over a 40-year period, the study said.

Only in a world where gas prices are 100% higher than the base case and there is a tax on carbon dioxide of $30 a ton does nuclear start to look cheaper than gas, based on the analysis.

And SCE&G is excluding some possibilities that could make the new reactors more expensive even in this scenario, Cooper said. "They never look at the full range of alternatives," he said. For example, cutting electricity demand through efficiency would be cheaper than building new gas plants, and would allow new generation to be built in spread-out intervals, further cutting costs versus the Summer units, he said.

Canceling the project would leave a substantial amount of money on the table. The study counts $1.9 billion already sunk into Summer by the end of 2012, in addition to $500 million in cancellation costs. When added to the base case, those sunk costs make the gas alternative more expensive than nuclear by only 0.3 cent per kWh. But assuming the costs of abandonment are amortized over 10 years, natural gas would then be cheaper by 1.3 cents per kWh. Using efficiency to delay and reduce the number of gas plants would reduce costs further.

"The cancellation of the construction of Summer 2 & 3 is very likely to lower consumer costs," the study concluded.

But SCANA believes that the new units are the best long-term strategy to have a balanced portfolio of one-third coal, one-third gas and one-third nuclear, company spokesman Eric Boomhower said in an email. "Our new nuclear strategy has been reviewed and approved numerous times, and has consistently been deemed prudent by the Public Service Commission of South Carolina," he said. "Our construction work on the new units is going well and the projected cost is approximately $615 million below our initial forecast from 2008."

Cooper also said Levy County would prove to be uneconomic. That project is not under construction, but Progress Energy Florida has recently been approved for cost recovery of about $105 million to help pay for work to obtain a license from the U.S. Nuclear Regulatory Commission.

Levy County will likely cost at least $4 billion more than a gas alternative, assuming no cost overruns, which could push the difference as high as $6 billion, Cooper's study said.

While Cooper admitted there are hypothetical scenarios in which the new plants could prove to be cheaper than alternatives, that prospect is risky for ratepayers. "That's a gamble the utilities have been unwilling to take with stockholder money. From the point of view of ratepayers, those ratepayers would be better off driving to Biloxi and playing the roulette table," he said.

Progress Energy Florida spokesman Sterling Ivey said in an email that he has not yet reviewed the study.

But Florida's other utility that has recovered costs for nuclear projects defended the practice as beneficial for customers. Cooper's study did not focus on Florida Power & Light Co. because "we've had success" with nuclear cost recovery, said Erik Hofmeyer, a spokesman for the NextEra Energy Inc. subsidiary. Only about 10% of FPL's cost recovery charges are being used to pay for development of potential new units at the Turkey Point plant. In a typical monthly bill of $94.25, about $1.65 in 2013 is for nuclear-related costs.

The utility has used most of the money to pay for 500 MW of uprates at its St. Lucie and Turkey Point plants, which will save customers $3.8 billion on fuel costs compared to purchasing fossil fuels, Hofmeyer said.

"Cost recovery is a proven approach that assists regulated utilities with financing for large infrastructure projects to provide the lowest cost to consumers," Nuclear Energy Institute spokesman Steve Kerekes said in an email. "It helps save customers money over the long term and it supports long-term rate stability, since the savings can amount to billions of dollars over the life of a project."

Load-Date: March 21, 2013

End of Document

Moody's: Vogtle Nuclear Plant Cost Hikes, Delays are Negative

The Bond Buyer

March 14, 2013 Thursday

Section: REGIONAL NEWS; Vol. 122; No. 50

Length: 389 words

Byline: Shelly Sigo

Body

Moody's Investors Service said Monday that adverse developments at Georgia Power's new Plant Vogtle nuclear construction project that have increased costs and delayed the construction schedule are a credit negative.

However, the costs and delays are manageable at the utility's A3 senior unsecured rating level. The outlook is stable.

On Feb. 28, in a semiannual Vogtle construction monitoring report filed with the Georgia Public Service Commission, Georgia Power requested a $381 million increase in the certified capital cost of its share of the project to approximately $4.8 billion from $4.4 billion, according to Moody's.

The power company also indicated that there would be an increase in financing costs to about $2.1 billion from $1.7 billion because of a delay in the scheduled completion date.

The cost increases and construction schedule delay follow several other negative project developments, including ongoing litigation with the construction consortium over $425 million of additional costs, more than 20 Nuclear Regulatory Commission license amendment requests as a result of deviations to the approved project design, and other concerns, according to Moody's analysts.

The commercial operation date for nuclear Unit 3 has been moved to the fourth quarter of 2017 from April 2016, and to the fourth quarter of 2018 from April 2017 for Unit 4.

Georgia Power, whose parent company is investor-owned Southern Co., owns 45.7% of the project while Oglethorpe Power Corp. owns 30%, Municipal Electric Authority of Georgia owns 22.7%, and Dalton Utilities 1.6%.

MEAG, a public generation and transmission organization, secured most of its financing in March 2010 through the sale of $2.62 billion of bonds.

The authority also has a $1.8 billion loan guarantee from the Department of Energy.

Officials at MEAG could not immediately be reached to find out if its costs will increase or it will require additional financing.

In October, Moody's affirmed its A2 rating on MEAG's $2.27 billion of project M and J bonds, and the Baa2 rating on $390.5 million of project P bonds financing the authority's ownership interest in the new Vogtle units.

Moody's said it was maintaining a negative outlook on MEAG's bonds "to reflect the uncertainty" over the cost dispute with contractors and potential pressure related to cost increases and delays.

http://www.bondbuyer.com

Load-Date: October 31, 2013

End of Document

MEAG Ratings Could Be Pressured by Nuke Plant Cost, Delays: Moody's

The Bond Buyer

March 27, 2013 Wednesday

Section: REGIONAL NEWS; Pg. 3; Vol. 122; No. 59

Length: 515 words

Byline: Shelly Sigo

Body

BRADENTON, Fla. - Moody's Investors Service said Tuesday that $2.7 billion of bonds issued by the Municipal Electric Authority of Georgia could be downgraded if early uncertainties in the construction of two nuclear units in Georgia lead to higher costs cost and further delays beyond those known so far.

The total cost for the new units 3 and 4 at Plant Vogtle originally was estimated at $14 billion to be shared by Georgia Power Corp. at 45.7%, Oglethorpe Power Cooperative at 30%, MEAG at 22.7%, and the city of Dalton at 1.6%. The units were originally projected to come online in 2016 and 2017.

Georgia Power, the builder, recently announced a $600 million construction cost increase and a delay in service of almost two years. Lawsuits are also pending with contractors disputing $900 million in additional costs, and a Georgia Public Service Commission construction monitor has warned about possible further delays.

"The early uncertainties on the ultimate cost and construction schedule of Vogtle nuclear units 3 and 4 give pause as to whether the project will face more serious credit challenges," said Moody's analyst Dan Aschenbach.

The construction schedule delay - "far surpassing expectations" - has exerted negative credit pressure on the MEAG's revenue bonds, Aschenbach said.

"Construction delays are a leading indicator of rising costs," he said. "We think that further delays and new cost over-runs are likely, and there is a finite level that will be tolerated by ratepayers, which could lead to a rating downgrade."

The project has shown recent progress with the pouring of special concrete for the foundation of the new reactors earlier this month.

Moody's said it believes factors that support the project as "an economic and long-term strategic resource" to MEAG Power and its participants, include fuel diversity, replacement generation for the decommissioning of other nuclear units, a predictable stable cost.

Jim Fuller, senior vice president and chief financial officer at MEAG, said the project is progressing and that cost increases as a result of schedule delays are "unfortunate but not unexpected for a project of this magnitude."

MEAG has been "very conservative" and anticipated these types of issues in its financing plans by including sufficient sources of capital when bonds were sold in 2010 and a conditional federal loan guarantee was obtained, he said.

"The cost impacts of the potential delay in the in-service date and related cost impacts are manageable and result in very small impacts to the forecasted production cost from the units and on MEAG Power's forecasted competitive wholesale system power costs," Fuller said.

MEAG secured most of its financing for the nuclear project in 2010 selling $1.03 billion of Project M bonds rated A2 by Moody's, $1.25 billion of Project J bonds rated A2, and $390.5 million of Project P bonds rated Baa2. The agency has an additional $1.8 billion loan guarantee from the Department of Energy.

Fitch Ratings and Standard & Poor's both rate the Project J and M bonds A-plus, while the Project P bonds are rated A-minus.

http://www.bondbuyer.com

Load-Date: October 31, 2013

End of Document

SCE&G says construction issues likely to delay new V.C. Summer nuke, add costs

SNL Energy Finance Daily

June 6, 2013 Thursday

Section: SNL Extra

Length: 404 words

Byline: Andrew Englblom

Highlight: South Carolina Electric & Gas Co. said June 5 that construction delays at its V.C. Summer nuclear project will likely push back the in-service date for at least the first of two planned units under construction at the site.

Body

South Carolina Electric & Gas Co. said June 5 that construction delays at its V.C. Summer nuclear project will likely push back the in-service date for at least the first of two planned units under construction at the site.

V.C. Summer unit 2 is scheduled to come online March 15, 2017, but Steve Byrne, COO and president of generation and transmission at the SCANA Corp. subsidiary, said at a briefing for analysts that construction troubles are expected to delay the start of operations until the fourth quarter of 2017 or first quarter of 2018.

Those delays, Byrne said, are the result of fabrication issues at a Lake Charles, La., factory that is building modules to be installed at the site. Some of the issues at the facility, he said, are likely startup issues, but others "we think go beyond normal startup issues."

He added that some modules have arrived on schedule or even early more recently, but that the company does not necessarily see that as a dependable trend.

Byrne did not provide a new in-service date for Summer unit 3, but that unit also could be affected, according to an executive on the call.

At the upper bounds, Byrne said the delays could add $200 million to SCE&G's 55% share of the cost of the project, but he cautioned that this is a preliminary estimate by SCE&G and not an estimate by its contractors, Westinghouse Inc. and Chicago Bridge & Iron Co. CB&I came to the project through its acquisition of The Shaw Group and has recently replaced the management team at the project.

Who will pay the cost of delays is not completely clear, he said.

Byrne said the delays remain within the 18-month grace period included in the schedule for the plant's construction that was authorized by the South Carolina Public Service Commission, but any delay is likely to add costs to the project.

Overall, though, the project remains under its initial $6.31 billion budget for SCE&G's share, and the company's most recent estimate provided to regulators at the end of May shows an estimated $5.77 billion cost of the project. Those savings, Byrne noted, are largely due to favorable financing and escalation costs.

"Sometimes you are lucky," he said.

The existing Summer plant is a single-unit, 980-MW facility. Each of the two new units will produce 1,117 MW. Santee Cooper, known legally as the South Carolina Public Service Authority, will own a 45% interest in each of the new units. It owns a 33% share of unit 1.

Load-Date: June 12, 2013

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Moody's: Construction delay at Summer nuke is credit negative for SCANA, Santee Cooper

SNL Energy Finance Daily

June 11, 2013 Tuesday

Section: SNL Extra

Length: 462 words

Byline: Amy Poszywak

Highlight: The most recent delay in the construction of two new units at SCANA and Santee Cooper's V.C. Summer nuclear plant in South Carolina is credit negative for both companies, Moody's said June 10.

Body

The most recent delay in the construction of two new units at SCANA Corp. and Santee Cooper's V.C. Summer nuclear plant in South Carolina is credit negative for both companies, Moody's said June 10.

Bill Hunter, Moody's vice president and senior analyst, said the estimate from SCANA's South Carolina Electric & Gas Co. subsidiary that its share of the cost increases related to the delay could be as much as $200 million translates to an increase of about $165 million for Santee Cooper. Thus, the project's total cost could increase by as much as $365 million as a result of the delay.

SCE&G will own a 55% interest in each of the units, while Santee Cooper will own a 45% interest.

The project's timeline and price tag still remain within the scope that Moody's had expected when the companies first announced it, and the new information does not affect the co-owners' ratings, Hunter said. However, with SCE&G attributing the delays to issues with the delivery of materials from The Shaw Group Inc., the contractor consortium, which includes Westinghouse Electric Co. LLC, is compromised, he said.

Hunter also noted that while SCE&G will need to go to the South Carolina Public Service Commission for approval to recover the additional construction costs in electric rates, the regulators previously have found such cost increase requests to be reasonable.

"A revised budget of approximately $6 billion (the most recent $5.8 billion budget and the possible $200 million overrun) would be within the level of some prior budgets approved by the SCPSC," Hunter wrote. "Since the originally approved budget in 2010, interim budgets have generally declined because lower cost escalation estimates owing to low inflation more than offset specific cost increases in the construction contract."

Additionally, Moody's considers notable regulatory support for the project to be an important credit driver for SCE&G and SCANA. For Santee Cooper, Moody's considers the fact that the utility can increase its rates without going through the approval process at the commission as a major credit support.

The delays and cost overruns, however, could challenge Santee Cooper's efforts to reduce its ownership stake in the project to 20%. Moody's considers execution of that plan to be critical for Santee Cooper to maintain its current ratings.

"The revised completion date range for Unit 2 (December 2017 to March 2018) remains within the SPSC's deadline of September 2018, but eats up some of the leeway," Hunter wrote. "The increase in costs highlights that the co-owners bear some price risk even though the construction cost is, at least in theory, largely fixed."

Shaw is a subsidiary of Chicago Bridge & Iron Co. Santee Cooper is known legally as South Carolina Public Service Authority.

Load-Date: June 17, 2013

End of Document

Santee Cooper s costs raising alarms $5.1B nuclear plant obligations worry credit rating firms as utility prepares to offer $1.75B in bonds

Post & Courier (Charleston, SC)

July 23, 2013 Tuesday

Section: 01,A; Pg. 1

Length: 1007 words

Body

Santee Cooper is heading to Wall Street. Its mission, in layman s terms, is to refinance part of its mortgage and take out a home equity loan, all on a scale never before seen in South Carolina.

With interest rates still low, the utility is shopping plans to offer nearly $1.75 billion in long-term bonds to investors.

It would be the largest debt issue in state history by a public agency.

It s also prompted three big credit rating firms to point out concerns they have about Moncks Corner-based Santee Cooper. In particular, they re worried about the $5.1 billion the state-owned power and water company is borrowing to help pay for its share of the V.C. Summer Nuclear Station expansion in Fairfield County.

The utility, which provides electricity to 2 million South Carolinians either directly or through local power cooperatives, is looking to sell four types of bonds with the help of Goldman Sachs and other big banks. The interest rates have not been set yet, but the proceeds are already allocated.

Santee Cooper said in presenta

tions to potential investors last week that about $541 million would pay for work at the Summer nuclear plant in Jenkinsville, north of Columbia.

Another $340 million would go toward meeting new environmental regulations and other expenses.

The bulk of the money, $867 million, would be used to refinance older, higher-interest bonds that come due as soon as December. The new debt would extend those obligations three or four decades into the future, said Mollie Gore, Santee Cooper s director of corporate communications.

We can take debt we previously had to repay by 2030, refinance it and pay it out over many more years, Gore said. That s the goal on this.

Overload?

Wall Street s big three credit ratings firm had mixed reactions to the deal, which would increase Santee Cooper s long-term debt load by about 17 percent, to $5.9 billion. All three last week assigned the fourth-highest ratings their firms use to grade the quality of bonds.

Gore pointed out that Standard & Poor s Ratings Services upgraded the utility s long-term debt to stable from negative, citing a new contract extension with Central Electric Power Cooperative, its biggest customer. S&P credit analyst David Bodek said the long-term agreement provides a predictable source of revenue through 2058 and enables Santee Cooper to better align the repayment of its existing and new debt.

Gore added that Santee Cooper remains highly rated among our utility peer group, and we are moving quickly on the opportunity to extend debt over the life of our assets, an opportunity that comes from successfully negotiating a contract amendment with our largest customer.

The two other big rating firms, Moody s Investors Service and Fitch Ratings, also view the deal with Central Electric as a positive move, but both issued downgrades on Santee Cooper. Moody s knocked the outlook on the utility s debt down one notch, which could trigger slightly higher interest rates on the new bonds, while Fitch revised its ratings outlook to negative.

Their shared concern and S&P agrees with them on this point is whether the utility can sell more than half of its ownership stake in the Summer nuclear plant, as it s been trying to do since at least 2011. If it can t, Santee Cooper, also known as the S.C. Public Service Authority, would be saddled with excess power and higher debt repayment costs once the expansion is completed.

The authority s 45 percent ownership interest in Summer leaves the utility with significant excess generating reserves for an extended period and potentially could weaken financial metrics below targeted levels, Fitch wrote in a report last week. The authority s ability to address these challenges over the next 12 to 24 months will be instrumental in resolving the negative outlook.

As for Moody s, it said it believes Santee Cooper s efforts to find a buyer for part of the nuclear plant and reduce its exposure to Summer will take longer than initially expected resulting in further tightening of the utility s financial and competitive position.

It also predicted a challenging period for Santee Cooper between now and the completion of the project in 2018. Its main worry is the enormous costs of adding the two new reactors. Even after the bond sale, Santee Cooper will still need to raise another $2.8 billion to pay for its $5.1 billion share, unless it finds a partner to pick up some of the tab.

These capital requirements will significantly increase the utility s leverage, and the nearly doubling of debt service over the next four years will test ratepayer acceptance of Santee Cooper s longer term power supply plan, Moody s wrote.

Paying it back

Mark Cooper, senior fellow for economic analysis at Vermont Law School s Institute for Energy and Environment, has taken the cost issue further.

Cooper has said nuclear plants are too expensive to build and operate. He also argued it would be more economical to halt construction and mothball the Summer expansion.

South Carolina Electric & Gas, which owns the other 55 percent of the project, has said the new reactors ultimately will save ratepayers billions of dollars because nuclear fuel costs almost nothing compared with coal and other fossil fuels.

Santee Cooper will be repaying the new debt with revenue from its electricity business. Gore said the utility previously approved a two-part rate increase totaling 7 percent to generate more revenue. Half went into effect in December. The rest kicks in at the end of this year.

A big part of that was focused on debt associated with environmental compliance and with the nuclear build-out, Gore said.

Santee Cooper has not announced any future rate increases.

The utility s board is expected to vote on the bond sale July 31.

Gore said it would be by far Santee Cooper s biggest debt sale in its 79-year history. Based on that, it also would be the largest ever for a public agency in South Carolina, according to the State Treasurer s Office.

Load-Date: July 23, 2013

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SCANA revises CapEx plans to reflect VC Summer delays

SNL Energy Finance Daily

August 2, 2013 Friday

Section: SNL Extra

Length: 484 words

Byline: Amy Poszywak

Highlight: SCANA Corp. executives on Aug. 1 presented an updated CapEx forecast that includes additional costs stemming from unexpected construction issues that have led to delays at its V.C. Summer nuclear project.

Body

SCANA Corp. executives on Aug. 1 presented an updated CapEx forecast that includes additional costs stemming from unexpected construction issues that have led to delays at the planned V.C. Summer nuclear expansion.

SCANA subsidiary South Carolina Electric & Gas Co. had announced in early June that project construction delays would likely push back in the in-service date for at least the first of two planned units at the site. During the company's second-quarter earnings call Aug. 1, executives said they now expect a similar delay for the second unit as well.

SCANA's revised CapEx estimates reflect the delay in the in-service dates by up to 12 months for unit 2, and a similar delay for unit 3. With unit 2 now expected to come online between the fourth quarter of 2017 and the first quarter of 2018, a similar delay could push the in-service date for unit 3 from 2018 into 2019.

Executive Vice President and CFO Jimmy Addison said during the call that while the construction consortium - Westinghouse Electric Co. LLC and Chicago Bridge & Iron Co. NV - have provided SCANA with their preliminary estimates of cash flow changes for unit 2, they do not yet have revised estimates for unit 3. SCANA has, however, prepared an internal estimate to evaluate the impact of a similar delay on unit 3, Addison said.

"To be clear, this is our current best estimate of the impact of the delay, and the numbers may shift intra-period as they are refined," the CFO said. "These numbers do not include the potential increased costs of up to $200 million, as we have not reached any further conclusions on those matters."

SCANA said it expects to have a more definite estimate of increased costs by the end of 2013.

According to the company's slide presentation, estimated CapEx across all SCANA business lines is now $1.42 billion, $1.63 billion and $1.51 billion for 2013, 2014 and 2015, respectively. The figures compare to the $1.61 billion, $1.70 billion and $1.48 billion estimated by SCANA at its June 5 analyst day.

The company maintains that the delays remain within the 18-month grace period included in the schedule for the plant's construction that was authorized by the South Carolina Public Service Commission. And while SCE&G will need to go to the commission for approval to recover the additional construction costs in electric rates, regulators previously have found such cost increase requests to be reasonable, according to Moody's.

Following the June announcement, Moody's said the delay was credit negative for SCANA and Santee Cooper, which will own a 45% interest of the new units' capacity.

The existing unit 1 at Summer has a current operating capacity of 980 MW, according to SNL Energy data. Each of the two new units will produce 1,117 MW. Santee Cooper is known legally as South Carolina Public Service Authority and owns a 33% share of the output of V.C. Summer 1, according to SNL Energy data.

Load-Date: August 8, 2013

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A CASE STUDY OF ECONOMIC COST AND RISKS ASSOCIATED WITH ADVANCE NUCLEAR GENERATION AND COMBINED CYCLE GAS TURBINES

Prepared by:
Howard Axelrod, PhD
Energy Strategies, Inc.

Prepared for:
Santee Cooper

8/19/2013
Confidential

STUDY OBJECTIVE

In 2005, Energy Strategies, Inc. developed a life cycle comparative economic model for Santee Cooper that evaluate nuclear, CCGT and coal generation options.

While not an optimization or generation expansion tool, it is a stochastic (Monte Carlo) model that computes the relative uncertainty or each option based on a range of input assumptions. Over 2,000 variable are assigned a unique probability distribution based on historical trends and professional forecasts.

The 2005 model has been updated with the latest available forecast and was used to assess the VCS nuclear plant to a state-of-the-art CCGT.

Three specific variable were evaluated that are expected to have significant impact on the comparative economics and associated economic risks of each option. Those three included: natural gas prices -it has been estimated that fuel represents 60 -70% of a CCGT's total costs; Carbon Tax -a $20/ton of CO_2 has been called for and translates into $10/MWH of operating costs; and Production Tax Credit -an additional $18/MWH tax credit available to an investor owned utility.

STUDY PARAMETERS

Two economic measures were calculated to compare the relative economics of nuclear versus CCGT:

Levelized (2012$) Unit Costs (Cents per kwh)

Total Net Present Value of "All-In" Capital and Operational costs
While there were over 2,000 probability distributions developed to evaluate the range of uncertainty, three Primary Drivers were further tested to evaluate the impact on comparative costs:

- Natural Gas Prices
- The Cost of C02 Mitigation (Le. Carbon Tax)
- Production Tax Credit

EVALUATIVE CRITERIA

Levelized Unit costs were used to compare this study results (Base Case assumptions) with other similar studies:

For example, our Base Case which used the 2012 EIA natural gas price forecast and with Carbon Tax found Nuclear levelized costs to be $94/MWH and CCGT at $82/MWH.

This compares to EIA estimates of $104 -$115 and $87 - $107. (see next slide) Note: while the nuclear mean value is $94, within 90% confidence the range is $72 -$139/MWH.

NPV Life Cycle Costs were also derived. Two power plants are considered economically equivalent if the difference in NPV is equal to zero. We measured the likelihood that the NPV was equal to, greater than or less than zero. For this analysis a Positive NPV meant that Nuclear was more expensive than CCGT.

THE 2013 EIA ENERGY OUTLOOK:
$108.4 FOR NUCLEAR & $93.4 FOR CCGT

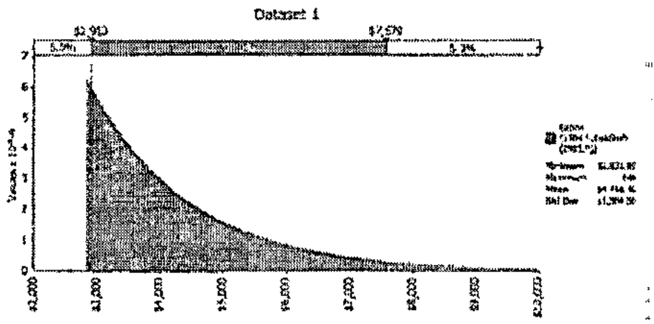
Regional Variation in Levelized Cost of New Dispatchable Cieneration Resources, 2018

Range for tolal system levelized costs (2011 $/megawatthour) for plants entering service in 2018

Plant type	Minimum	Average	Maximum
Oispatchabte Technologies			
Conventional Coal	89.5	100.1	118.3
Advanced Coal	112.6	123	137.9
Advanced Coal With CCS	123.9	135.5	152.7
Natural Gas-fired			
Conventional Combined Cycle	62.5	67.1	78.2
Advanced Combined Cycle	60	65.6	76.1
Advanced CC with CCS	87.4	93.4	107.5
Conventional Combustion Turbine	104	130.3	149.8
Advanced Combustion Turbine	90.3	104.6	119
Advanced Nuclear	104.4	108.4	100.3
Geottlermal	81.4	89.6	100.3
Biomass	98	111	130.8

ESTIMATED NUCLEAR CAPITAL COSTS FOR AP1000

	2008$	2012$
TVA	2516$	3,058
NRG	2900$	3,525
FPL	3108$	3,778
SoCo	4363$	5,303
SC	4386$	5,331
FPL	4540$	5,518
Duke	4924$	5,985



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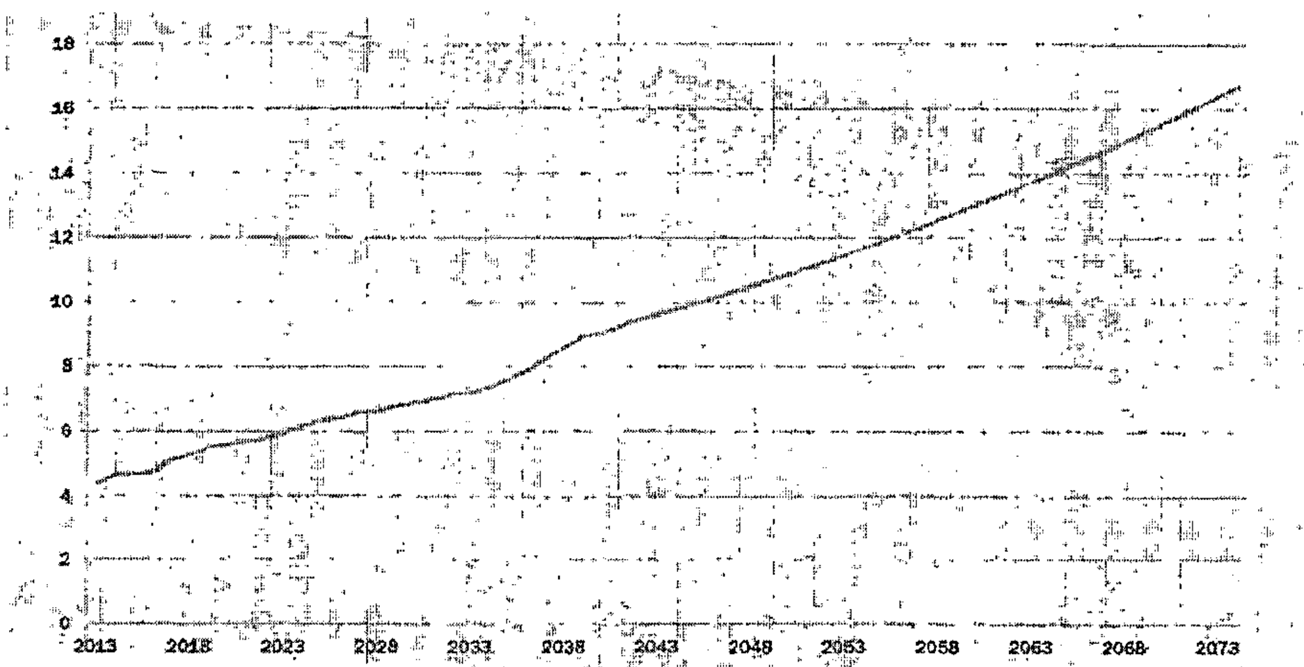
Natural Gas Price Forecast



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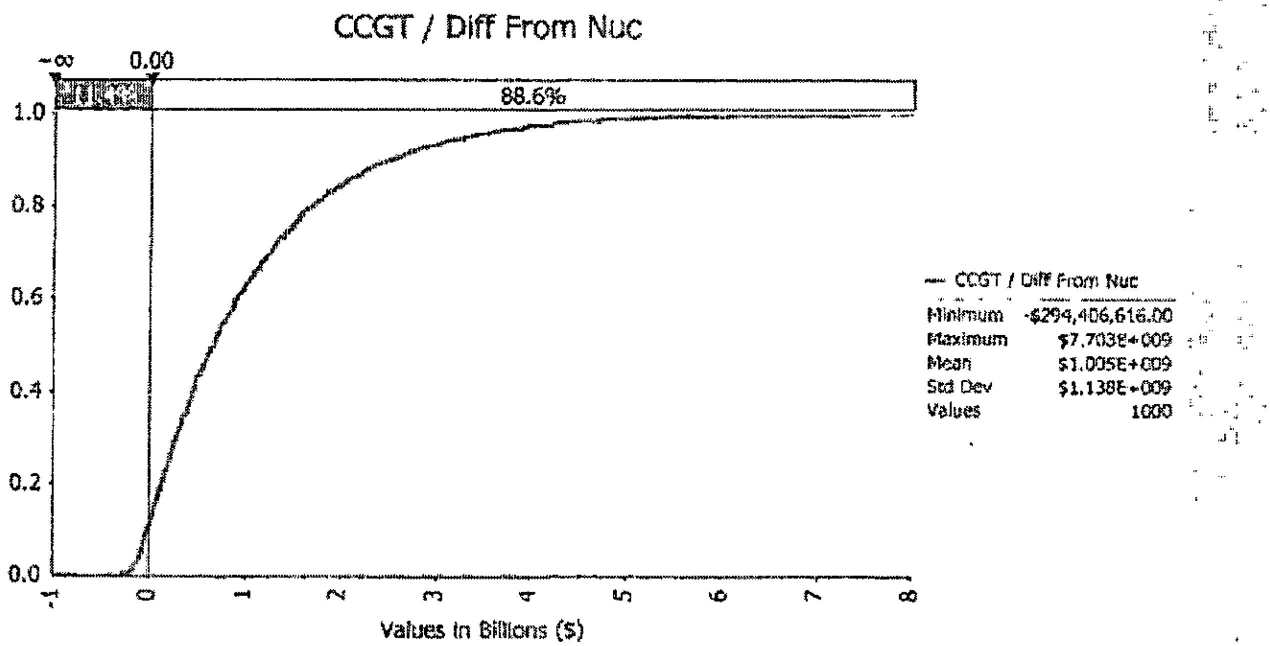
ABOUT THE COMPARISON

The following set of graphs represent the cumulative probability of possible outcome for the net difference in NPV between equivalent nuclear and CCGT units.

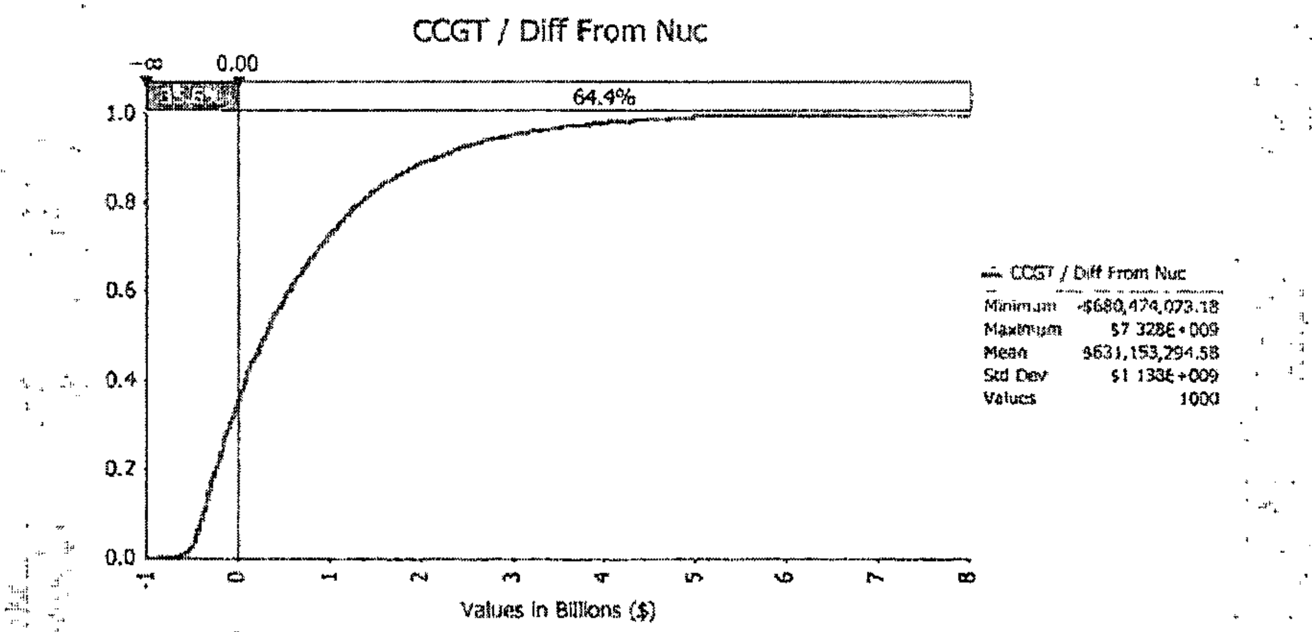
With the cursor (vertical line) set at "zero", the probability that the NPV would be above or below zero is determined.

For Case 1, there is an 81.5 percent chance that the NPV is above zero which means that 81.5% of the time, CCGT would be more economical than nuclear when using the range of assumptions defined for this case.

BASE CASE: NO CO2, NO PRODUCTION TAX CREDIT (PTC), ADJ EIA NAT GAS
CCGT HAS AN 88.6% CHANCE OF BEING MORE ECONOMICAL



BASE PLUS CO2 (PROB.)
CCGT HAS A 64.4% CHANCE OF BEING MORE ECONOMICAL



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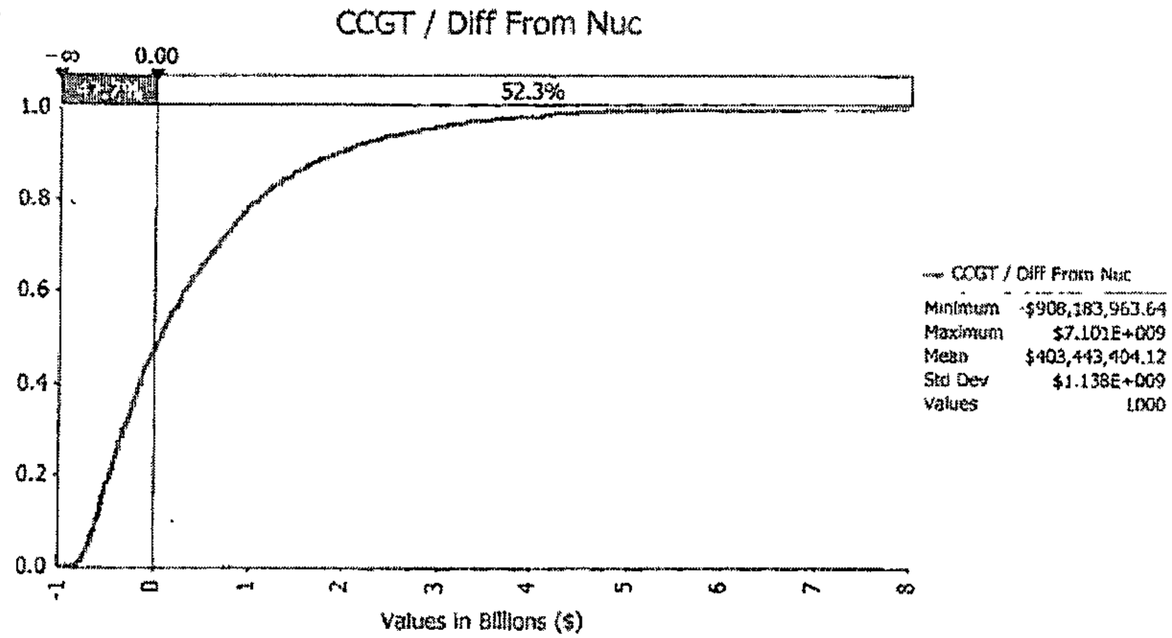
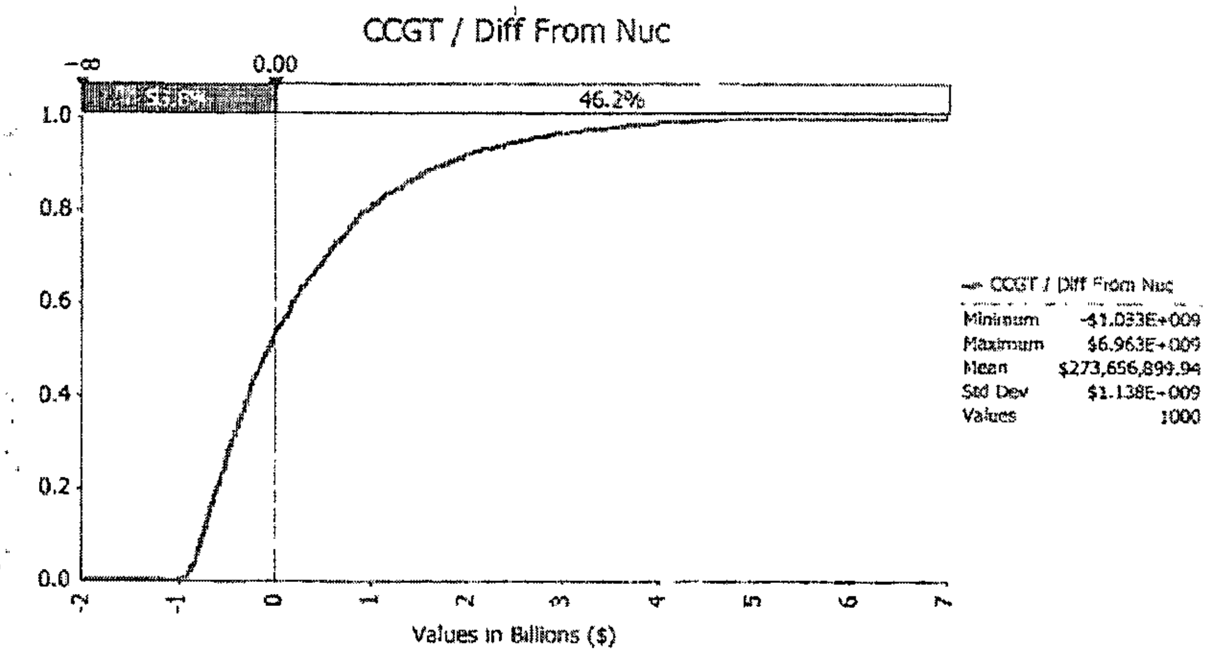
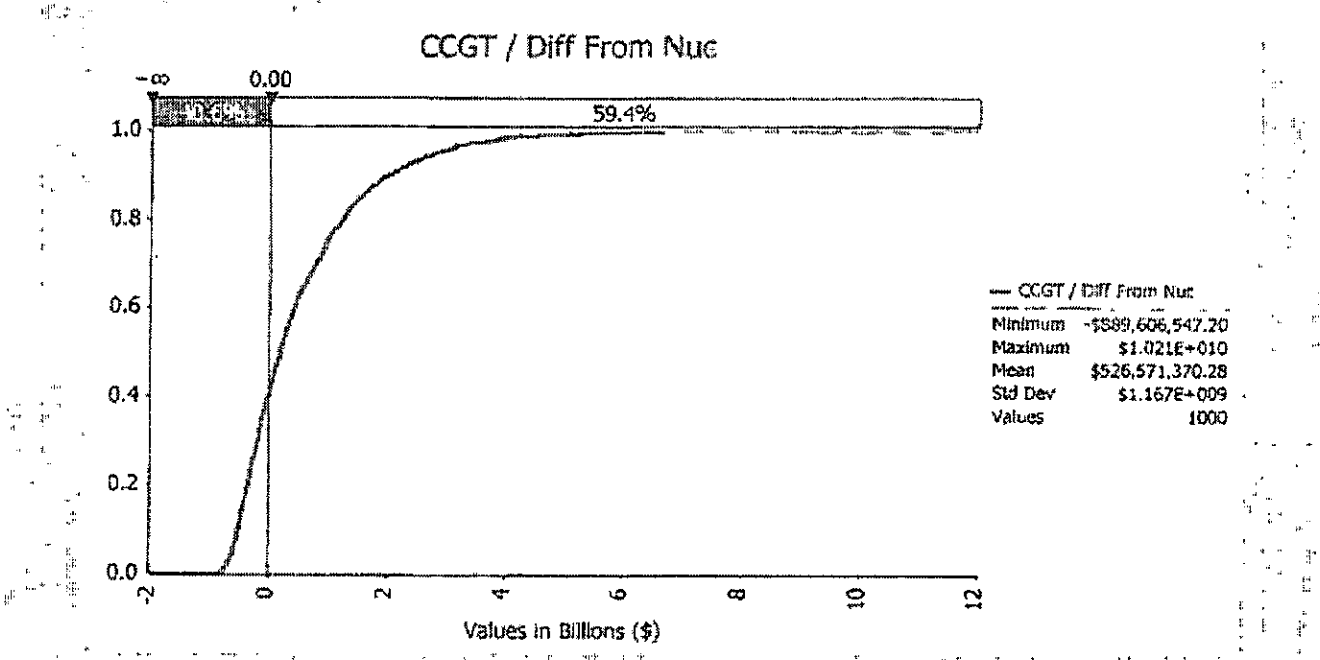
BASE PLUS CO2 (PROB.) & PTC: CCGT HAS A 52.3% CHANCE OF BEING MORE ECONOMICAL



BASE PLUS CO2 ($20) & PTC NUCLEAR HAS A 53.8% CHANCE OF BEING MORE ECONOMICAL



EIA NAT GAS ONLY (UPPER RANGE) CCGT HAS A 59.4% CHANCE OF BEING MORE ECONOMICAL



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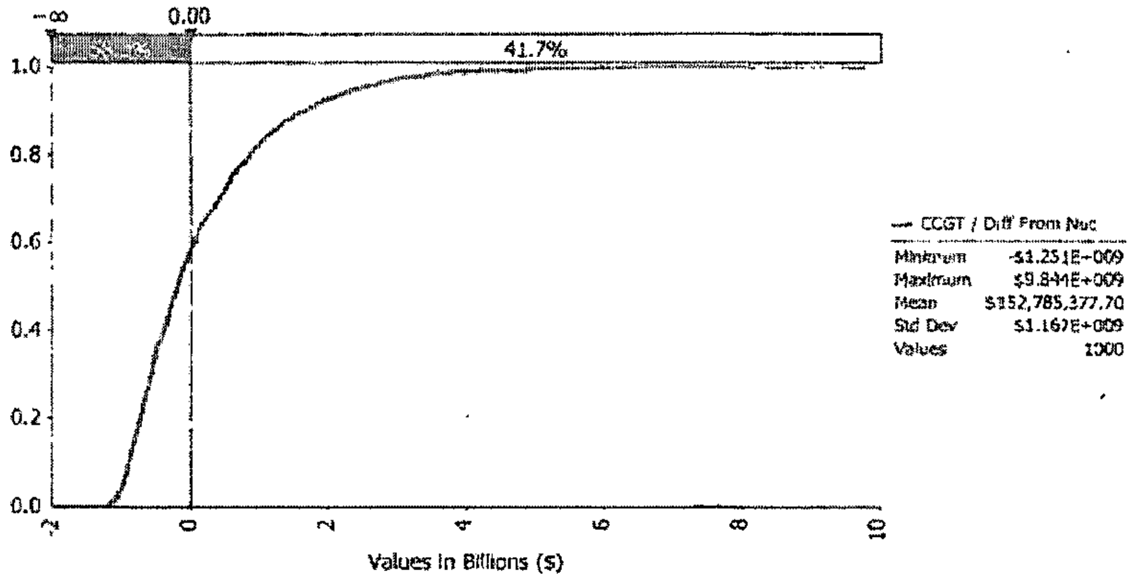
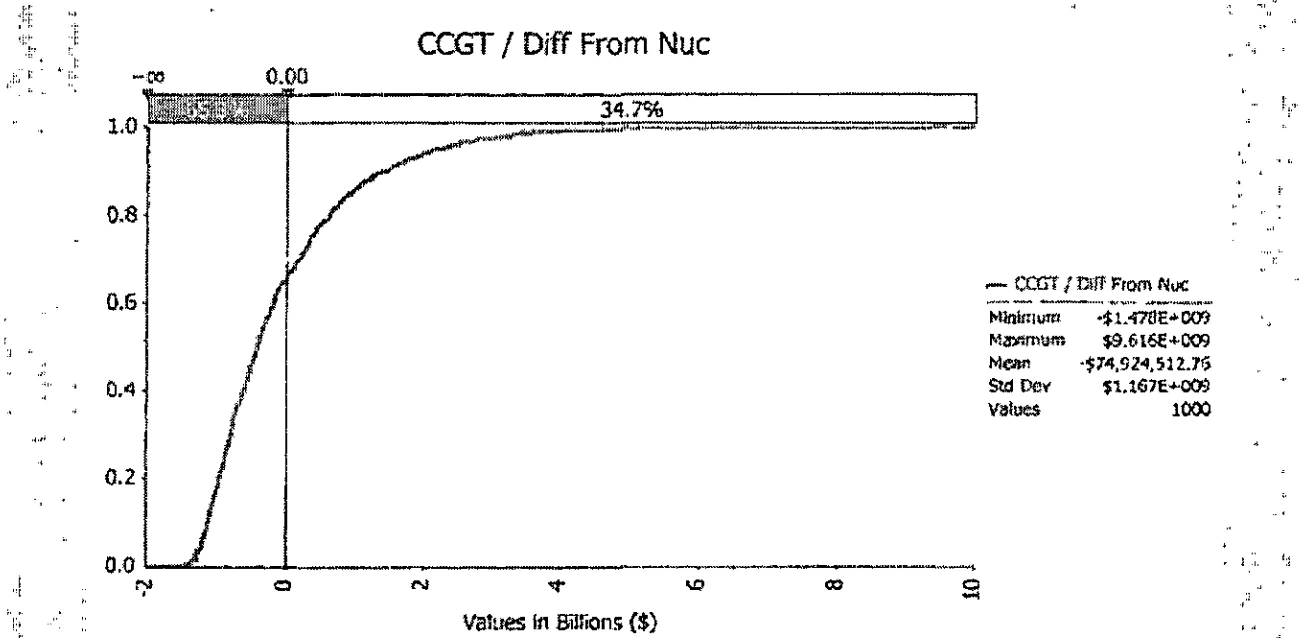
EIA NAT GAS PLUS CO2 PROB NUCLEAR HAS A 58.3% CHANCE OF BEING MORE ECONOMICAL

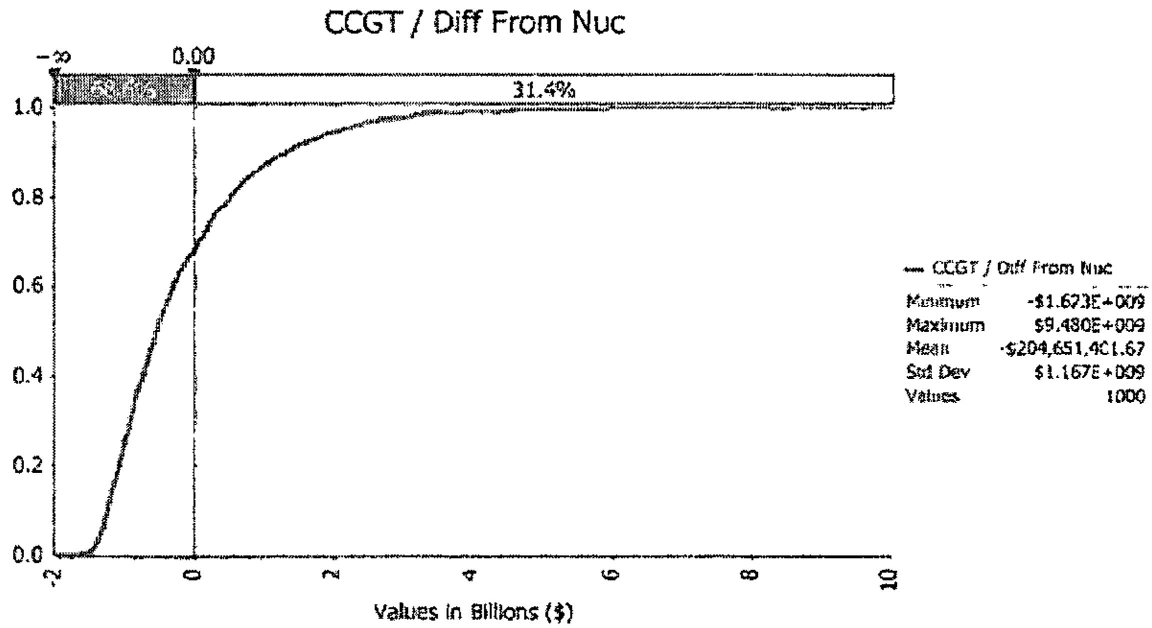
CCGT / Diff From Nuc



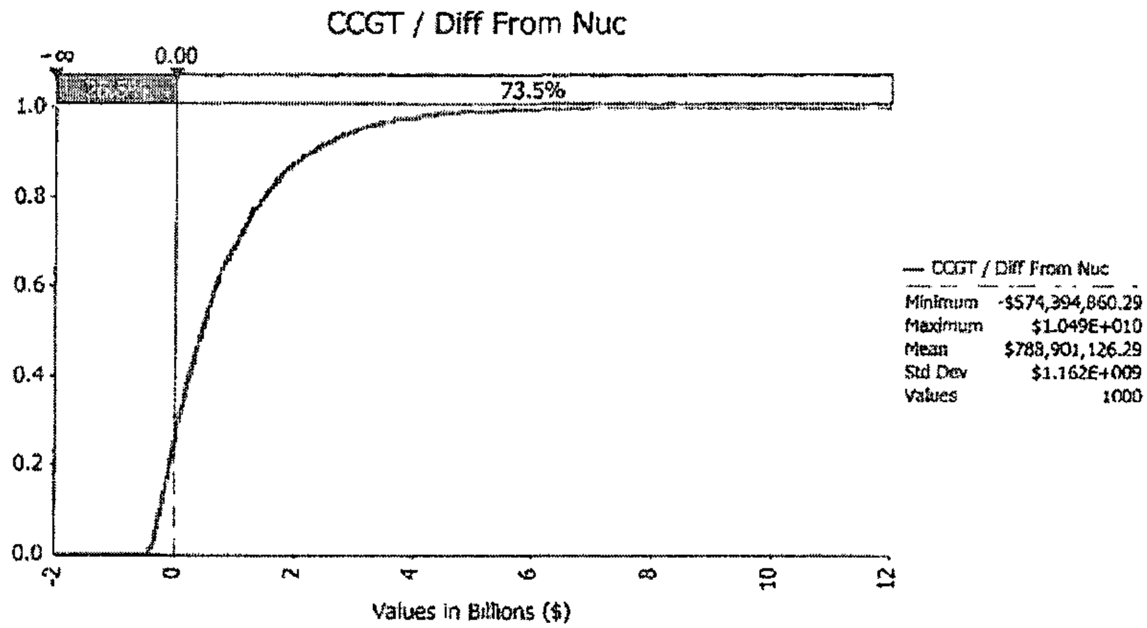
EIA NAT GAS, PROB. CO2, PTC
NUCLEAR HAS A 65.3% CHANCE OF BEING MORE ECONOMICAL



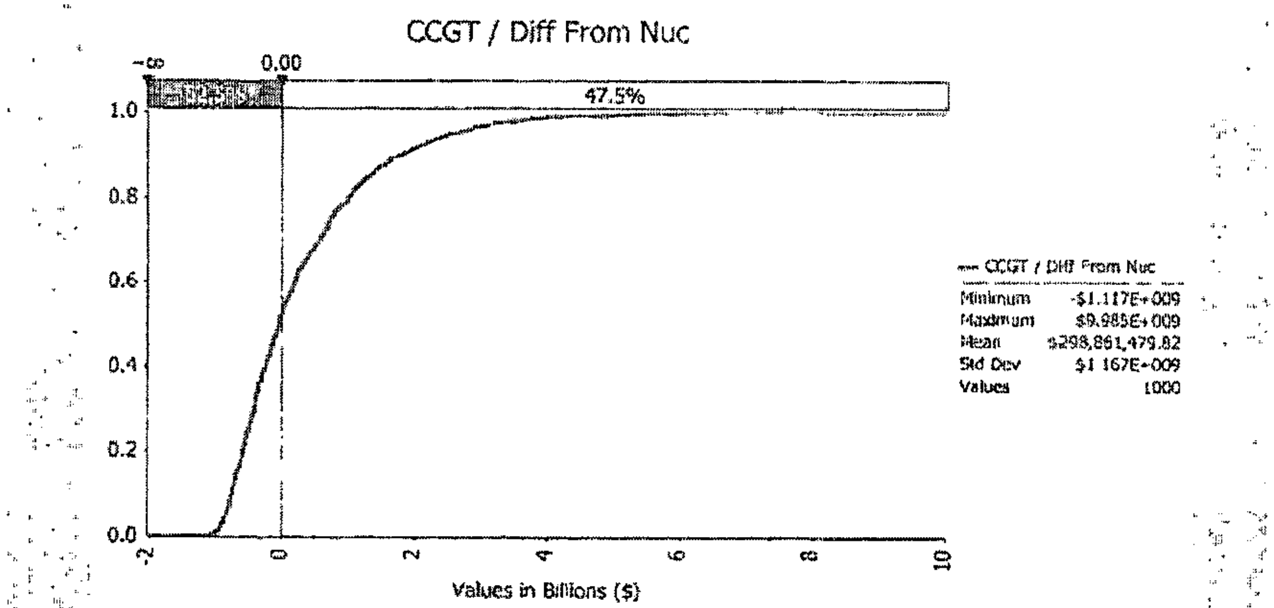
EIA NAT GAS, $20 CO2, PTC NUCLEAR HAS A 68.6% CHANCE OF BEING MORE ECONOMICAL



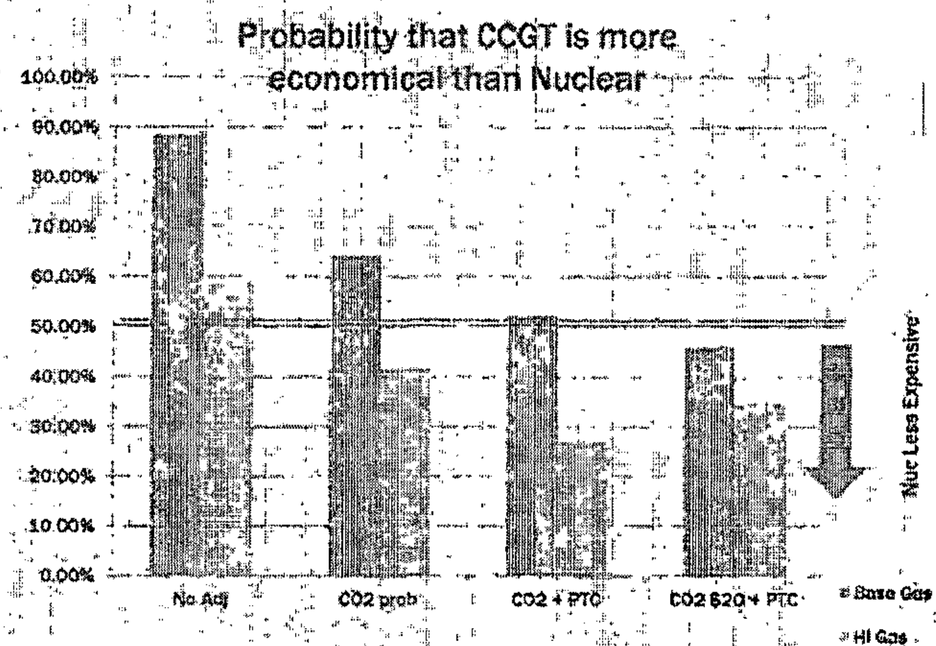
SPECIAL CASE FOR DUKE
BASE NAT. GAS PRICE AND PTC:
WHILE LOW NAT GAS PRICES STILL DRIVE THE ECONOMICS IN FAVOR OF CCGT, THE PTC GENERATED OVER $200 M IN NPV AND REDUCED THE PROBABILITY FROM 88.6% TO 73.5%.



SPECIAL CASE FOR DUKE
AT THE EIA NAT. GAS PRICE FORECAST & PTC, THERE IS A 52.5% CHANCE THAT NUCLEAR IS MORE ECONOMICAL. THIS COMPARES TO 40.6% WITHOUT PTC.



SUMMARY: AT CURRENTLY PROJECTED NATURAL GAS PRICES & EITHER NO OR MODERATE CARBON TAX, CCGT HAS ECONOMIC ADVANTAGE. AT MODERATELY HIGHER NAT. GAS PRICES, NUCLEAR IS THE MORE LIKELY ECONOMICAL CHOICE



SUMMARY OF FINDINGS

EIA has increased its expectation of rising natural gas prices which, at least for the next few years, is over 20% higher than its 2012 forecasts and 50% higher than current prices included natural gas futures.

Using a moderately reduced forecast, CCGT has a significant economic advantage over nuclear.

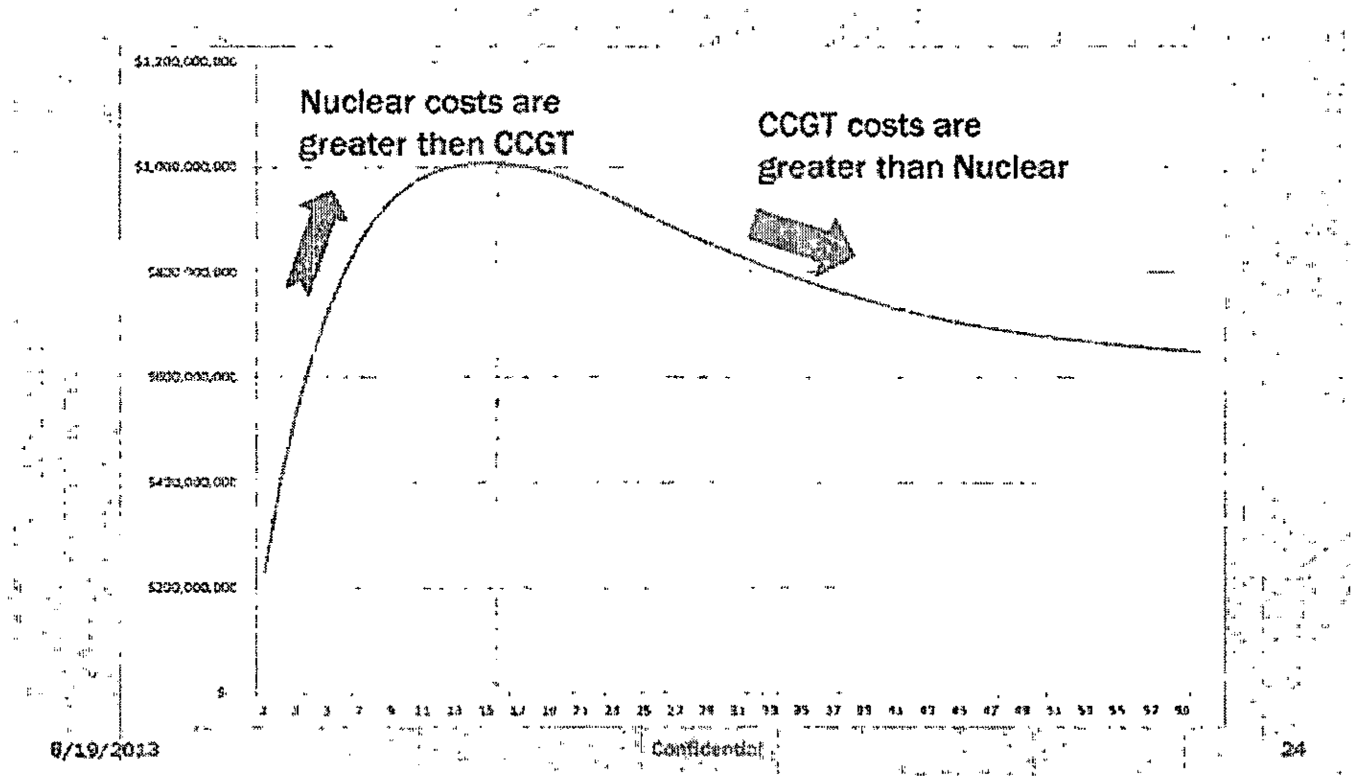
However, as natural gas prices rise and carbon emission costs become internalized, nuclear generation offers significant economic benefits.

WHILE GAS PRICES AND CO2 MITIGATION WILL DRIVE ECONOMIC ADVANTAGES FOR NUCLEAR, ANNUAL REVENUE REQUIREMENTS AND FINANCIAL CONSIDERATIONS ARE ALSO PARAMOUNT.

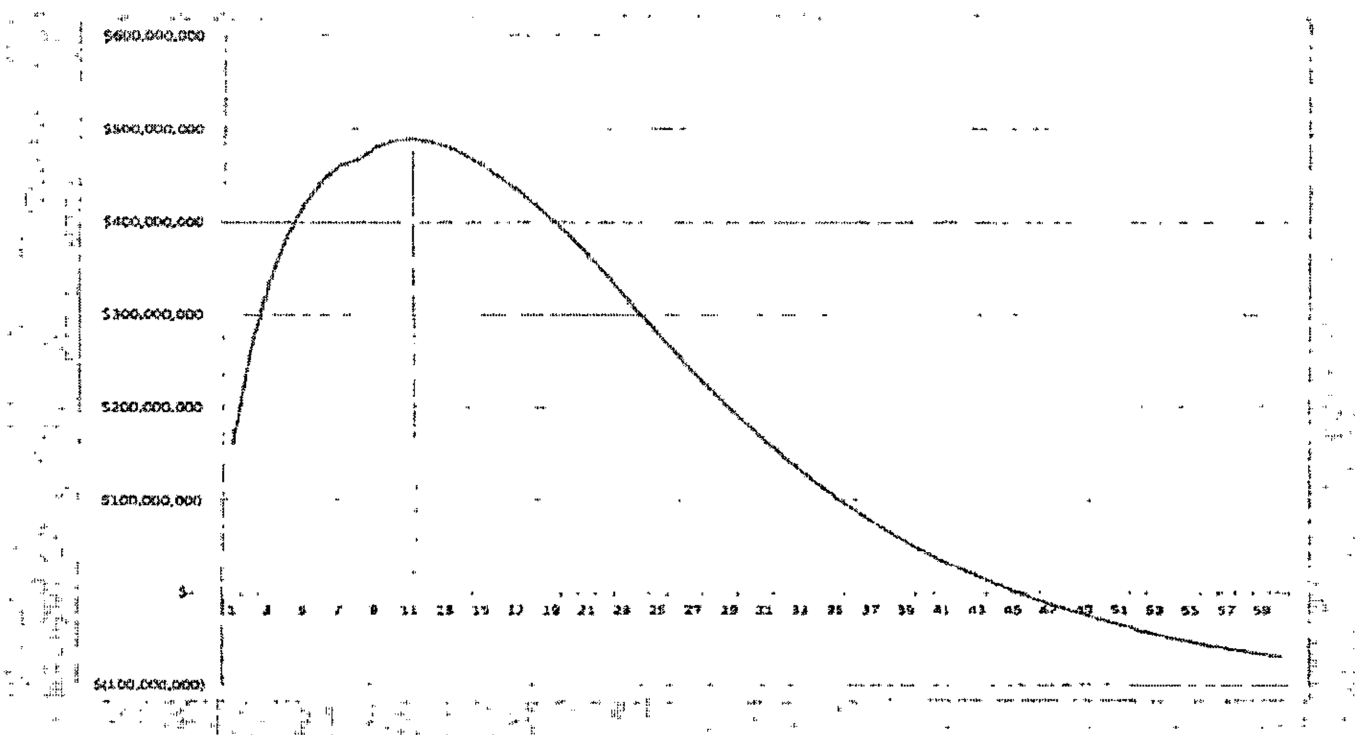
The NPV and Levelized analyses present only one dimension that needs to be considered. For example, as natural gas prices rise and CO2 costs are incurred, the overall economic benefit of advanced nuclear generation could produce $billions in savings for the consumer.

However, when comparing annual cost differences, even under highly favorable conditions, annual costs for nuclear will likely exceed CCGT costs for a number of years. While consumers may benefit from nuclear over time, the crossover point could be anywhere from 15 to 30 years. The point of payback could range from 35 -50 more years. The following two examples demonstrate this issue.

THE ATTACHED GRAPH IS THE CUMULATIVE DIFFERENCES IN ANNUAL TOTAL COSTS (2012$) FOR CASE 2. WHILE THE DIFFERENCE BETWEEN NUCLEAR AND CCGT DIMINISHES, IT TAKES ~16 YEARS TO ACHIEVE A POSITIVE BENEFIT FOR THE NUCLEAR OPTION. THE PEAK "LOSS" APPROACHES $1 BILLION, BUT IS REDUCED TO ABOUT $.6 BILLION BY THE END OF ITS OPERATING LICENSE.



THE FOLLOWING GRAPH IS FOR CASE 6. IT HAS AN 82% CHANCE OF BEING MORE ECONOMICAL THAN A CCGT WITH A MEAN LIFETIME BENEFIT OF $75 MILLION. YET, ANNUAL TOTAL COSTS EXCEED CCGT FOR 11 YEARS, WITH FULL PAYBACK IN 46 YEARS.



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THERE IS ALSO OTHER FINANCIAL CONSIDERATIONS

For an Investor Owned Utility, assuming both plants have identical NPV revenue requirements, capital recovery including profit margins is about $3.5 billion for the CCGT; whereas, for the nuclear option, capital recovery exceeds $13.7 billion.

In other words, with consumers having an equal benefit, albeit deferred for nuclear, the nuclear owner can achieve up to $10 billion in added profits.

However, this added return does come with risk. For example, a one year delay in start-up could incur over $500 million in financing charges per plant.

WHAT DOES ALL THIS MEAN FOR SANTEE COOPER:

It is very likely that natural gas prices will begin to rise and that global
warming issues will drive regulations that result in carbon mitigation costs.

While it may take a few years to realize these changes, the economic advantage of VCS will become transparent.

Besides the financial advantage available to IOUs, there is also the opportunity to capture available Production Tax Credits (-$18/MWH)

Offsetting these advantages to both public power and IOU are the inherent pre-operational risks associated with schedule and construction costs. Delays at Vogtle have already incurred -$700 million in added costs.

While a PPA offers a buyer far less risk, the annual cost for nuclear, especially during the first 10 -20 years would be greater than a comparable CCGT, although somewhat more competitive to the average regional market price that would include older, less efficient generation. Santee may have to offer a short to intermediate term PPA that produces revenues below actual costs.

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COMPARISON OF ADVANCED NUCLEAR GENERATION TO CCGT

Sources of Information:

- EIA Energy Outlook 2012 & 2013 (Prelim.)
- Economics of Nuclear Power: World Nuclear Organization (Dec. 2012)
- A Manual for the Economic Evaluation of Energy Efficiency and Renewable Energy Technologies, National Renewable Energy laboratory, March 1995

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santee cooper

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Confidential Contract Negotiations

August 23, 2013

Kevin B. Marsh
Chairman & CEO
SCE&G
220 Operation Way D302
Cayce, South Carolina 29033

Dear Kevin:

For almost two years, SCE&G and Santee Cooper have been working with the Consortium (Westinghouse and CB&I) to correct submodule delivery issues from the Lake Charles fabrication facility. When we discussed these problems earlier this year, we were hopeful that the Chicago Bridge & Iron (CB&I) acquisition of The Shaw Group (February 2013) would have an overall positive impact on the project, and particularly, a positive impact on the Consortium's ability to fabricate and deliver submodules.

On April 9, 2013, we met in Columbia with CB&I executive leadership to review its module fabrication status, to include its plan to correct Lake Charles performance issues. CB&I committed to deliver 83 submodules by the end of 2013. Several days after the meeting, CB&I provided its submodule delivery schedule, also dated April 9, 2013, which committed CB&I to only 69 submodules for the remainder of 2013.

As anticipated, the CB&I submodule delivery schedule was integrated into the overall project schedule and resulted in a delay to substantial completion of V.C. Summer Unit 2. This delay was quantified as nine to twelve months and publicly announced to the financial community by SCE&G at an Analyst Day presentation June 5, 2013.

As I am sure you are aware, based on the CB&I schedule, only five of thirteen scheduled submodules have been delivered as of this writing. Although early indications seemed positive that CB&I executive management were engaged in improving the performance at Lake Charles, the delivery record unfortunately demonstrates otherwise, placing the project schedule in jeopardy once again. I know you agree that this is unacceptable.

The Consortium's inability to deliver submodules has been a major source of concern and risk for this project for a long time. At the last president's meeting on June 21, 2013, the Westinghouse and CB&I discussion demonstrated that they do not function well as a team to resolve critical project issues. The Consortium's schedule performance, including any associated module delay costs currently embedded in project costs or future claims against the project, are simply unacceptable to Santee Cooper. Our view is that the Consortium's inability to fulfill their contractual commitments in a timely matter places the project's future in danger. SCE&G and Santee Cooper need to examine together the remedies provided for under the EPC for the Consortium's failure to perform and exercise the fullest extent those remedies to protect our interests.

Kevin, based on our discussion, I know that you share my concern for the fabrication of the submodules in a timely manner. This has become a critical issue for the project and our companies I recommend that we meet with our senior team members involved in the project and develop a plan forward. The plan should make clear that we hold the Consortium accountable for the costs to our companies and should insist on the Consortium providing a realistic plan that can be executed by the Consortium to fabricate and deliver the submodules in a timely manner to complete the project on schedule.

Please call me soon to further discuss this matter.

Sincerely,

Lonnie

Lonnie N. Carter

LNC:alh